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THIS IS WESTERN OIL SANDS

Working

WesternOilSands

3. Highlights **4.** Corporate Governance and Board of Directors **6.** Chairman's Message **8.** President's Message **12.** Operations **22.** Management's Discussion and Analysis **47.** Financial Statements and Notes **78.** Corporate Information

ANNUAL MEETING The Annual General Meeting of the Shareholders of Western Oil Sands will be held on Wednesday, May 10, 2006 at 3:30 p.m. at the Calgary Petroleum Club, Calgary, Alberta.

Working to create shareholder value by capturing and developing large, world-class hydrocarbon resources – this is our vision. Our journey began six years ago and 2005 marked our second full year of operations. Our success with the first phase of the Muskeg River Mine Project is leading to further expansion and development that will result in a continuous construction strategy as we fully develop our bitumen resources. As part of our long-term strategy, Western's plans also include research and development efforts to add value to our existing assets, downstream initiatives to reduce our exposure to heavy oil differentials, and identifying and evaluating opportunities in resource development of oil sands and other ventures with significant long-life hydrocarbon resource potential.

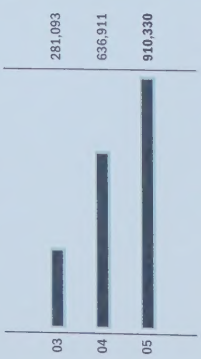
CORPORATE PROFILE Western Oil Sands Inc. is a Canadian corporation that holds a 20 per cent undivided ownership interest in a multi-billion dollar Joint Venture that is exploring a portion of one of the largest crude oil reservoirs in the world. The Athabasca Oil Sands Project ("AOSP") uses established processes to mine oil sands deposits, extract and transport bitumen, and upgrade the bitumen into synthetic crude oil and vacuum gas oil. Western is developing strategies to increase its production to 100,000 to 120,000 barrels per day over the next eight to ten years. Western is also pursuing other oil activities related to technology development, downstream initiatives and large, long-life resource capture. As an entrepreneurial, growth-oriented company, our goal is to continue to identify opportunities to enhance shareholder value. Western's shares trade on the Toronto Stock Exchange under the symbol WTO.

Over the past year, Western has worked diligently to deliver on our growth strategy and, ultimately, create further value for our shareholders. Strong commodity prices in 2005 and enhanced operational reliability and efficiency resulted in a year of record financial and operating performance. We are excited about the opportunities that lie ahead and believe the best is yet to come.

- Gross revenue rose 43 per cent in 2005, primarily as a result of an 18 per cent increase in production, combined with a 44 per cent increase in blended price realizations.

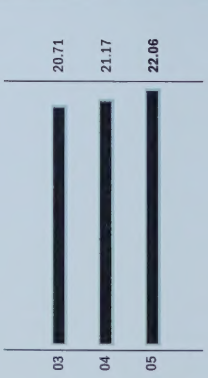
- Unit operating costs per processed barrel of bitumen were $25.44 in the first quarter of 2005 due to forced operational outages. Over the next three successive quarters, where we achieved record production, unit operating costs averaged $21.22 per processed barrel of bitumen, of which $5.10 per barrel relates to natural gas.

EBITDAX
($ thousands)



Revenue
($ thousands)

Production
(bbls/d)



Operating Costs per Processed Barrel ($)

HIGHLIGHTS

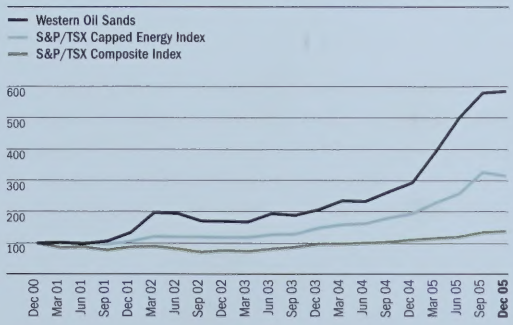
	2005	2004	% Change
Operating Data			
Bitumen Production *(bbls/d)*	**31,994**	27,108	18
Synthetic Crude Sales *(bbls/d)*	**42,534**	36,210	17
Operating Expense per Processed Barrel *($/bbl)*	**22.06**	21.17	4
Realized Crude Oil Sales Price – Oil Sands *($/bbl)* (1)(2)	**49.91**	34.60	44
Financial Data *($ thousands)*			
Gross Revenue	**910,330**	636,911	43
Cash Flow from Operations (3)	**244,231**	23,044	960
Net Earnings Attributable to Common Shareholders (6)	**149,449**	19,452	668
EBITDAX (1)(5)	**307,008**	87,587	251
Net Capital Expenditures (7)	**46,833**	39,968	17
Total Assets	**1,590,520**	1,470,870	8
Long-Term Financial Liabilities (8)	**706,880**	716,094	(1)
Long-Term Debt	**565,655**	662,620	(15)
Per Share Information			
Net Earnings per Share *($/Share)*			
Basic	**0.93**	0.12	675
Diluted	**0.92**	0.12	667
Cash Flow per Share – Basic *($/Share)* (1)(4)	**1.52**	0.15	913
Share Information			
Closing Share Price on the TSX – December 31 *($/share)*	**27.81**	13.95	99
Weighted Average Shares Outstanding (Basic) *(thousands)*	**160,169,887**	156,926,514	2

- Robust commodity prices, together with sustained reliable operations over 2005, resulted in a new annual record for EBITDAX. Our fixed-price hedging program expired at the end of fiscal 2005 and, as a result, we will take full advantage of actual commodity prices in 2006 as we have no hedges in place for the year.

(1) Please refer to page 44 for a discussion of non-GAAP financial measures.
(2) The realized crude oil sales price is the revenue derived from the sale of Western's share of the Project's synthetic crude oil, net of the risk management activities, divided by the corresponding volume. Please refer to page 25 for calculation.
(3) Cash flow from operations is expressed before changes in non-cash working capital.
(4) Cash flow per share is calculated as cash flow from operations divided by weighted average common shares outstanding, basic.
(5) Earnings before interest, taxes, depreciation, depletion, amortization, stock-based compensation, accretion on asset retirement obligation, foreign exchange and risk management as calculated on page 34.
(6) Western has not paid cash dividends in any of the above referenced fiscal years.
(7) Net capital expenditures are capital expenditures net of any insurance proceeds received during the period.
(8) Long-term financial liabilities includes long-term debt, option premium liability and lease obligations. Prior years are restated to include lease obligations.

Cash Flow per Share
($)

Net Earnings per Share
($)



Share Performance
($)

Western's Board of Directors possesses significant, broad-based technical and international experience and, as an entrepreneurial, growth-oriented company, Western is able to leverage and capitalize on this experience.

CORPORATE GOVERNANCE

Western's Board is committed to adhering to a high standard of corporate governance practices. The Board believes this commitment is in the best interests of shareholders and it also promotes effective decision making at the Board level. The Board's view is that its approach to corporate governance is appropriate and complies with the objectives and guidelines relating to corporate governance adopted by the Toronto Stock Exchange.

COMPOSITION OF THE BOARD

Western's Board currently consists of 10 directors who provide a wide diversity of business experience. Eight of the Board members are independent of management and are unrelated directors. Each of the unrelated directors is free from any business or other interest or relationship, other than interests and relationships that arise solely as a result of shareholding, which could reasonably be perceived to materially interfere with the director's ability to act in the best interests of Western.

BOARD COMMITTEES AND THEIR MANDATES

The Board has five committees, each comprised of three directors, all of whom are unrelated directors. The committees are: Audit Committee, Compensation Committee, Corporate Governance Committee, Health, Safety and Environment Committee, and Reserves and Business Risk Committee.

Audit Committee
Chair: Robert G. Puchniak
Members: Randall Oliphant, Mac H. Van Wielingen

The Audit Committee approves Western's interim unaudited consolidated financial statements and press releases and reviews the annual audited consolidated financial statements and certain corporate disclosure documents including the annual information form, management's discussion and analysis, and offering documents, including all prospectuses and other offering memoranda, before they are approved by the Board. The Committee reviews and makes a recommendation to the Board in respect of the appointment of the external auditor and it monitors accounting, financial reporting, control and audit functions. The Audit Committee meets to discuss and review the audit plans of external auditors. The Committee questions the external auditor independently of management and reviews a written statement of its independence based on the criteria found in the recommendations of the Canadian Institute of Chartered Accountants. The Committee must be satisfied that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from its financial statements and it periodically assesses the adequacy of those procedures. The Audit Committee must approve or pre-approve, as applicable, any non-audit services to be provided to the Corporation by the external auditor. In addition, it reviews the internal control procedures to determine their effectiveness and to ensure compliance with Western's policies and avoidance of conflicts of interest. The Committee has established procedures for dealing with complaints or confidential submissions that come to its attention with respect to accounting, internal accounting controls or auditing matters.

Board of Directors: (left to right top row) **David J. Boone, Geoffrey A. Cumming, Tullio Cedraschi, James C. Houck, Oyvind Hushovd**
(left to right bottom row) **John W. Lill, Randall Oliphant, Robert G. Puchniak, Guy J. Turcotte, Mac H. Van Wielingen**

Compensation Committee
Chair: John W. Lill
Members: Tullio Cedraschi, Oyvind Hushovd

The Compensation Committee reviews succession plans for key management positions within Western, human resource policies and plans and the performance and development of the Chief Executive Officer and other senior officers of Western. The Committee makes recommendations to the Board with respect to the salary and other remuneration to be awarded to senior executive officers of Western. It also makes recommendations to the Board in respect of all other compensation matters including long-, medium- and short-term incentives such as bonus, stock option and performance share unit plans and other benefits and is responsible for developing these programs. The Committee is responsible for ensuring that the Company's compensation is linked to meaningful and measurable performance targets.

Corporate Governance Committee
Chair: Mac H. Van Wielingen
Members: Geoffrey A. Cumming, Oyvind Hushovd

The mandate of the Corporate Governance Committee is to assess the effectiveness of the Board as a whole, the various other committees, as well as individual directors. It also assesses Western's approach to corporate governance and monitors the relationship between management and the Board. This Committee is responsible for recommending candidates to the Board for nomination as directors and for the composition of various Board committees and for recommendations regarding Chairmanship of the Board.

This Committee, together with the Compensation Committee, also reviews and recommends compensation for Board and committee service. The Corporate Governance Committee is also mandated to undertake those initiatives as are necessary to maintain a high standard of corporate governance practices and, in this respect, monitors and considers for implementation the corporate governance standards that are proposed by various Canadian regulatory authorities or that are published by various non-regulatory organizations in Canada.

Health, Safety and Environment Committee
Chair: David J. Boone
Members: Tullio Cedraschi, John W. Lill

The Health, Safety and Environment Committee's mandate is to monitor the health, safety and environmental practices and procedures of Western and its subsidiaries for compliance with applicable legislation, conformity with industry standards and prevention or mitigation of losses. It reviews, reports and, when appropriate, makes recommendations to the Board on Western's policies and procedures related to health, safety and the environment.

Reserves and Business Risk Committee
Chair: Randall Oliphant
Members: David J. Boone, Geoffrey A. Cumming

The Reserves and Business Risk Committee's mandate is to (i) establish guidelines and procedures to assist management in identifying the principal risks of Western's business and implement appropriate systems to manage, mitigate and assess those risks and (ii) assist the Board in fulfilling its oversight responsibilities generally and under National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*. In fulfilling its mandate, the Reserves and Business Risk Committee meets with the independent qualified reserves evaluator to review the evaluation report of the Company's bitumen reserves, the corporate summary of the reserves and future net revenues of the oil sands properties and other related matters. In addition, it reviews the selection and qualifications of the qualified independent evaluator, the scope of work and the consistency of practices, standards and definitions applied in connection with the evaluation.

With two full years of operations behind us, I am very proud of the progress and achievements of the Athabasca Oil Sands Project ("AOSP") to date. The AOSP reached new, sustained levels of performance and achieved significant improvements above design capacity in 2005, resulting in record production, cash flow and net earnings for Western. Since Western's initial public offering in early 2001, shareholders have seen the Company's share price rise at a compounded annual rate of return of approximately 42 per cent, reflecting the rapid growth of the business. Looking ahead, 2006 and beyond promises to be an active and exciting time for Western. Planning with respect to the AOSP expansions is moving forward and, pending final investment approval of the first expansion, which is expected in the third quarter of 2006, construction is expected to commence before the end the year. Baseline work and planning continues to progress regarding the Omnibus application for further AOSP expansions. All of this adds to my enthusiasm for Western as we execute our strategy and deliver on our potential.

LONG-TERM STRATEGIC PLAN

Over the past year, the Board has been working very closely with Western's management team to formulate and execute on the Company's long-term strategic plan. The primary focus of this strategy is to deliver operational excellence from our existing assets and the expansion plans of our truly world-class AOSP. Over the longer term, Western's growth strategy also includes examining and capturing new business development opportunities. This includes modest research and development efforts with the objective of creating incremental value from our existing assets through technology enhancements, downstream initiatives to reduce the Company's exposure to heavy oil differentials and natural gas and, finally, the identification and capture of opportunities with significant hydrocarbon resource development potential. The predominant principle with respect to this strategy continues to be a relentless drive for the creation of shareholder value. Without question, shareholder value guides Western's decision making on a day-to-day basis and is a deep-rooted value within the culture of this organization.

CORPORATE GOVERNANCE

Western's Board is committed to the highest standards in corporate governance. We continue to place a high priority on having best-in-class polices and procedures in place. This commitment means we continue to review and ensure the Board's structure aligns with all appropriate governance standards and represents the necessary mix of skills and experience to guide the organization.

This last year was one of leadership change for Western. Several noteworthy changes took place on the Board. With my transition to Chairman in April, Mr. Geoff Cumming was appointed Lead Director. With the retirement of Mr. Brian McNeil, Mr. Walter Grist and Mr. Glen Andrews from the Board during the year, we welcomed Mr. David Boone, previously President, Offshore and International Operations for EnCana Corporation and now President of Escavar Energy; Mr. Randall Oliphant, formerly CEO of Barrick Gold; and Mr. Jim Houck, Western's new President and Chief Executive Officer. Jim brings over 35 years of global energy industry experience to Western and

Guy J. Turcotte
Chairman of the Board

we are already seeing the results of his leadership. I want to personally thank Brian, Walter and Glen for their excellent service on Western's Board. Their leadership through Western's start-up to an operating company was outstanding.

In late 2005, Mr. John Frangos announced that he was stepping down as Executive Vice President and Chief Operating Officer. As a co-founder of Western, John has left an indelible mark on the Company and he continues to provide guidance and sound business acumen to the organization, advising management in the area of corporate development. With John's support, there was a smooth transition period for Mr. Steve Reynish as he assumed the role of Executive Vice President and Chief Operating Officer. Steve was the Chief Operating Officer at the Muskeg River Mine for the AOSP and he was instrumental in delivering the sustained results that Western recorded in 2005. Steve now holds the critical position of Western's officer interfacing with the AOSP as the Company moves forward with its expansion strategy.

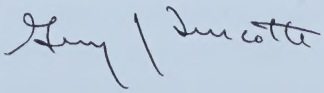
I believe the leadership of Western is as strong as ever and the Company is well positioned to deliver on its growth strategy. The Board and management team of Western are a highly committed, diligent, principled and entrepreneurial group of individuals focused on creating shareholder wealth.

LOOKING AHEAD

With growing global awareness of Alberta's Athabasca oil sands – where total production is nearing one million barrels of oil a day and is expected to rise to four million barrels through $100 billion worth of investment by 2020 – Western is extremely proud to be a part of this dynamic and growing energy sector. Through 2005, we saw the well-defined and massive resource base of the oil sands continue to achieve recognition on the world stage and its strategic value gain in significance. Within the oil sands space, Western's position continues to grow. In 2005, Western virtually doubled its undeveloped land position and the Company's future resource potential is a key asset. In addition, from a financial perspective, Western is clearly in a strong position to embark on its expansion initiatives. We are confident of future success; however, we balance this with a keen awareness of the highly variable and dynamic industry in which we compete. We know that there are considerable opportunities and challenges that lie ahead and Western will meet them head-on.

In closing, I would like to express my sincere thanks to all my fellow directors who serve as stewards of your Company. The Board would also like to thank Western's management team and employees for their commitment and hard work during the year and wish them continued success.

On behalf of the Board of Directors,



Guy J. Turcotte
Chairman
March 28, 2006

As many of you know, I joined Western last year and it has been an active, exciting and rewarding year for the Company. Guy Turcotte, now Chairman of the Board of Directors, along with Western's highly talented management team, assisted greatly in making my transition to President and Chief Executive Officer a smooth one, and I am appreciative of their support and leadership.

It has been clear to me since joining Western that the Company's vision – "to create shareholder value through opportunity capture and development of large, world-class hydrocarbon resources" – truly drives this organization. With our primary asset being our 20 per cent interest in the Athabasca Oil Sands Project ("AOSP"), Western has generated a compounded equity rate of return to shareholders of approximately 42 per cent over the past five years. In this way, we have seen our vision become a reality. That said, we believe this is just the beginning – with more exciting opportunities to come.

ATHABASCA OIL SANDS PROJECT UPDATE

In 2005, the Joint Venture Owners, together with the operations teams at the Muskeg River Mine and the Scotford Upgrader, were very focused on delivering reliable, sustainable production, and driving down our unit operating costs to maximize profitability for our shareholders. Through this activity, Western achieved record quarterly production rates. We believe reliable, sustainable results are an important measure of performance and our goal is to continue building on this track record. In fact, production optimization is an area that continues to be a high priority for the Joint Venture, and it will represent an ongoing effort over the life of the Project as we work to maximize the value of this incredible resource. While we're very pleased with the performance of the AOSP in 2005, we also know there is great potential to improve on our results to date. In 2006, a key objective continues to be identifying opportunities to optimize and enhance the value of these world-class assets. We are also looking forward to a successful turnaround that is scheduled for the second quarter of 2006. Much attention and planning has been directed to this effort, and we look forward to returning to full production and seeing sustained reliability and increased throughput in our operations.

In 2005, Western, together with its Joint Venture Owners, announced a continuous construction expansion strategy that would expand the AOSP in three "building blocks". This strategy takes into account valuable learnings from the original project execution and new construction techniques. With respect to the first expansion phase or building block, the Joint Venture made excellent progress during the year, and we expect to arrive at a final investment decision in the third quarter of 2006. To complete project milestones, the Joint Venture Owners are using a world-class management gating process. Each gate must be successfully completed before proceeding to the next. This management tool has been critical to the successful execution of our continuous construction expansion strategy – particularly in light of the escalating costs of materials and services that the energy industry experienced first-hand in 2005.

Concurrent with this process, certain long lead time items were ordered in 2005 to ensure these critical path capital items are delivered at the appropriate time to maintain our schedule and budget. Baseline work and planning is continuing regarding

James C. Houck
President and Chief Executive Officer

the permit application for our second and third expansion phases and the Joint Venture anticipates having this in place by 2008.

For the years 2007 through to 2009, Western implemented strategic crude oil hedges on a percentage of our share of future synthetic crude oil production from our existing operations. With this program in place, we have ensured a solid financial position during the years where our capital requirements for future AOSP expansion phases are significant. Western has no hedges in place for 2006, allowing us to take full advantage of robust commodity prices.

The plans associated with the AOSP's continuous construction expansion strategy and optimization projects will see Western's production grow to 100,000 to 120,000 barrels per day over the next eight to ten years. Beyond this, in terms of our future growth opportunities, Western is party to an Area of Mutual Interest ("AMI") and Participation Agreement that allows us to participate in the development of additional leases in the Athabasca region. In 2005, Shell completed the acquisition of several leases in the Athabasca region, building on the existing land position and virtually doubling our undeveloped land position with the AMI. As a proud and active owner, the AOSP is truly a world-class asset and we see tremendous growth potential in the years ahead.

Subsequent to year-end, in March 2006, Chevron announced that it acquired five heavy oil leases in the Athabasca region. The resource has the potential for recovery using in-situ recovery methods. These leases also fall under the AMI and Western will have the opportunity to participate to our 20 per cent interest.

PERFORMANCE HIGHLIGHTS

During 2005, Western exceeded many key financial and operating performance measurements compared to the previous year. We achieved record cash flow from operations of $244 million, including hedging losses of $110 million, compared to $23 million in fiscal 2004, approximately a ten-fold increase. On a per share basis, this represents $1.52 per share compared to $0.15 per share in fiscal 2004. Net earnings increased by a factor of seven to $149 million compared to $19 million in fiscal 2004 and, on a per share basis, net earnings were $0.93 in 2005 compared to $0.12 in the prior year. Gross revenue increased 43 per cent to $910 million in 2005 compared to $637 million during fiscal 2004.

Western's share of production averaged 31,994 barrels per day in 2005 compared to 27,108 barrels per day in 2004. This represents a year-over-year increase of 18 per cent. Fourth quarter production averaged 35,572 barrels per day, resulting in three successive quarters of record production rates. These sustained record quarterly production levels are a direct result of our production optimization initiatives. To achieve these higher availability rates, increased levels of maintenance and the costs associated with this activity are required. As a result, operating costs totalled $250 million in fiscal 2005 compared to $213 million in 2004. On a per barrel of processed bitumen basis, costs were $22.06 per barrel in 2005 compared to $21.17 per barrel in 2004. Pressure on cost of materials and services in a high commodity price environment, increasing natural gas prices, combined with these higher maintenance costs, resulted in the moderate year-over-year increase.

HIGHLIGHTS

- In October 2005, we announced a strategic risk management program to enhance our financial position as we progress through future AOSP expansions. The program uses a series of put and call options covering fiscal 2007 through to 2009, providing a floor price of US$52.42 per barrel on 20,000 barrels per day of production, with a ceiling price of US$92.41 on an average 13,333 barrels per day over the same period.
- To stimulate additional trading liquidity and generate a broader shareholder base, at our Annual General Meeting in May 2005, we received approval for a three-for-one division or share split of our issued and outstanding Class A Common Shares. Western's shares started trading on a post-split basis on May 30, 2005, and by year-end appreciated 46 per cent.

GROWTH STRATEGY

In addition to our concentrated focus on the AOSP, Western's growth strategy includes maintaining under evaluation several potentially significant project opportunities, each of which is designed to create long-term shareholder value. In 2006, approximately 17 per cent of our capital budget is directed to this activity.

As part of this strategy, Western is identifying and evaluating significant value-creating opportunities that may potentially contribute large, low-cost, long-life reserves. Other initiatives include modest research and development activity with the objective of identifying ways to add value to our existing assets; evaluating the potential of in-situ opportunities, which comprise approximately 80 per cent of the estimated resource base in the Athabasca region; and assessing potential downstream opportunities in order to minimize the impact associated with heavy oil differentials.

STRATEGIC ORGANIZATIONAL APPOINTMENTS

During 2005, Western augmented its organizational capabilities, ensuring that we are well positioned and poised for continued growth.

Effective January 1, 2006, Mr. John Frangos, a co-founder of Western, stepped down as Executive Vice President and Chief Operating Officer. His leadership, to all of us at Western, has been outstanding and he has served all of the shareholders during an extraordinary period of start-up and growth. John was instrumental in the conception and development of both Western and the AOSP and we applaud him for his passion, drive and inspired leadership. He will continue to be actively involved in advising Western's Board and management on our corporate development activities. John's role has been assumed by Mr. Steve Reynish, formerly the Chief Operating Officer of Albian Sands Energy. Steve has transitioned quickly into his new role and he is a valuable addition to the Western team as the AOSP moves into an aggressive expansion phase.

- Western achieved record performance in several key areas in 2005 including cash flow, earnings, revenue and production. Our goal is to continue building on this track record – delivering reliable, consistent results supported by an unwavering commitment to operational excellence.
- Western augmented its senior management team during the year with strategic organizational appointments. With these appointments, Western is well positioned to continue delivering on its vision to create shareholder value from its existing AOSP assets and from the development of new energy-based opportunities.

In mid-2005, Mr. David Dyck was promoted to Senior Vice President Finance and Chief Financial Officer and, in November 2005, Mr. Gerry Luft was appointed Vice President Downstream to reflect his increased responsibilities, which include leading all of our efforts to maximize the value of our synthetic crude oil products downstream of the mining operations. We also announced the appointment of Mr. Simon Hatfield as Vice President and Managing Director Oil & Gas. Mr. Hatfield is leading our business development efforts to identify long-life opportunities with significant hydrocarbon resource potential. In addition to these appointments, we have added high-level technical and managerial expertise to our organization to capitalize on our strengths and opportunistically expand our investment horizons.

LOOKING AHEAD

2006 promises to be an active and dynamic year for Western. This is an exciting time to be engaged in the energy sector and, as an entrepreneurial, growth-oriented company, we look forward to the opportunities and challenges that lie ahead in our quest to create value for our shareholders. This is our vision. This is Western Oil Sands.

In closing, I want to extend my sincere thanks to the staff, management and Board of Western for their hard work, enthusiasm and dedication over the past year. Also, on behalf of the Board, I want to thank our shareholders for your continued support.

James C. Houck

James C. Houck

President and Chief Executive Officer
March 28, 2006

Reliability and greater throughput continued to improve operational performance through 2005 to achieve record production for the year. We will continue to identify opportunities to optimize and enhance the value of our assets over the life of the Project. We believe this is real value creation for our shareholders.

OPTIMIZATION

Striving for operational excellence through high reliability, availability and maintenance is a key focus of our operations. As operating experience grows, the Joint Venture continues to identify production optimization initiatives to realize the full potential of our world-class resource base and operating assets.

Oil sands mining and upgrading processes, such as those used at the AOSP, are complex and technical operations that integrate many established engineering and chemical processes. Our teams of project operators at the Muskeg River Mine and Scotford Upgrader are constantly adjusting and fine-tuning the processes to optimize operations and production from the Project.

allows the AOSP to maintain full production while repairs and maintenance occur on one of the two other lines. Further production optimization initiatives are ongoing and include, for example, the addition of a closed loop water cooling circuit to improve energy efficiency. Modifications are also proposed at the Upgrader to process the heaviest product streams into lighter, higher-value

Operational reliability steadily improved during the year as the Joint Venture gained valuable operating experience. In 2005, we achieved record production of 31,994 barrels per day, representing an 18 per cent increase over the previous year. In June 2005, the AOSP marked a significant milestone when the Project achieved cumulative production of 100 million barrels of bitumen production after just over two years of operations.

Overall, we are pleased with the Project's operating performance and successful production optimization initiatives during 2005. Three successive quarters of record production is evidence of our focused efforts in this area. The annual results include the impact of an unplanned shutdown of one train at the Scotford Upgrader in the fourth quarter of 2004 that continued into the first quarter of 2005.

A range of production optimization initiatives were successfully completed during 2005 including the addition of a third tailings line at the Mine which

crude oil blend components. Plans also include the addition of a third hydroconversion unit and associated utilities.

The first major maintenance turnaround of the AOSP is scheduled to commence in the second quarter of 2006. Both trains at the Muskeg River Mine and the Scotford Upgrader will be shut down for maintenance. Taking into account a period where we will be slowing down operations prior to the shutdown and a subsequent ramp-up period to full production, it is anticipated that operations will be interrupted for approximately eight weeks before resuming normal operations before mid-year. Since commencing operations in 2003, this is the first major turnaround in what will be a regular event every three years.

As we move forward, our focus is on sustainable development and operational excellence. As part of an ongoing process, Western and its Joint Venture Participants will continue to identify opportunities to optimize and enhance the value of these assets, which will occur over the life of the Project.

EXPANSION

In early 2005, Western announced a continuous construction growth strategy that would expand the AOSP in three building blocks of approximately 100,000 barrels per day each. This approach, combined with production optimization initiatives, will see Western's production grow to 100,000 to 120,000 barrels per day over the next eight to ten years.

The continuous construction growth strategy the Joint Venture announced in early 2005 takes into account key learnings from the original project execution, new construction techniques and operating experience. Based on this growth strategy, each expansion phase or building block will be sized at approximately 100,000 barrels per day and construction of the first expansion phase is planned to commence before the end of 2006 on the east side of Lease 13, concurrent with a similar-sized expansion at the Scotford Upgrader. With this continuous construction strategy, the Joint Venture believes unnecessary costs associated with repeatedly mobilizing and demobilizing large teams of people would be avoided. In addition, we will achieve economies of scale in many areas including engineering costs, logistics, Owners' costs and volume purchasing.

To ensure solid project management, the Joint Venture Owners have adopted a management system or gating process which requires strict adherence to a staged protocol. The system consists of a scouting phase and three distinct gates. Each gate must be successfully completed before proceeding to the next. For the first 100,000 barrel per day expansion, the Joint

Venture Owners anticipate moving through the final gate, where we optimize the final scope of the first expansion phase and arrive at a final investment decision, in the third quarter of 2006. The Joint Venture is working diligently to ensure that the design of this first expansion phase is carefully optimized because it will provide the template for the next expansion phases.

Through this gating process, the scope of the first expansion was defined in more detail and optimized to include the construction of certain common infrastructure, such as pipelines, utility systems and permanent camps, which will be sized to support the longer-term production goal of over 500,000 barrels per day for the Project.

Due to a heated global market for engineering equipment and bulk materials, it is clear there has been a significant upward trend in construction costs over the past year. While cost estimates for the first expansion phase will not be completed until the third quarter of 2006, the Joint Venture's current view is that the first

phase, including infrastructure required to support subsequent expansions, could be up to $200 per annual barrel of production.

During 2005, major contractors were selected for both the Mine and Upgrader expansions. The AMEC-Colt engineering joint venture will complete the final phase of front-end engineering of the Mine expansion and, following a final investment decision, they will be well positioned to undertake the engineering, procurement and construction management of the mine expansion. Bechtel Canada Co. has been selected as the major contractor for the Upgrader expansions.

In April 2005, Shell, on behalf of the Joint Venture, filed regulatory applications for both the Mine and the Upgrader to take productive capacity to approximately 300,000 barrels per day at the Project level. Regulatory approval for this first expansion phase is anticipated in mid-2006.

Construction of the first expansion phase on Lease 13 and at the Scotford Upgrader is expected to start before the end of 2006 with completion in 2009, subject to a final investment decision and regulatory approvals. Production from the first expansion phase is expected to be brought onstream in late 2009, with full bitumen production anticipated in 2010. Actual timing will depend on the regulatory process, market conditions, final project costs and approvals and sustainable development considerations. Baseline work and planning is continuing with respect to the Omnibus application for the second and third expansion phases for our permits. The Joint Venture expects to have permits in place regarding this application in 2008.

Under the terms of the Joint Venture Agreement, the Owners have in place an Area of Mutual Interest ("AMI") and Participation Agreement. The AMI stipulates that the Project Owners have rights to participate in additional leases acquired by any one of the Joint Venture Participants in the Athabasca region.

In terms of future growth opportunities, Shell completed the acquisition of several leases in the Athabasca region in 2005, including Leases 309, 310 and 15 as well as 351, 352, 631 and 632. These acquisitions build on the land position above leases 88 and 89 and enhance the AOSP's position on the west side of the Athabasca River – in close proximity to Leases 9 and 17. Shell also added 12 quarter sections of land around Fort Saskatchewan, adjacent to the Scotford Complex, to support expansion activities at the Scotford Upgrader.

The AOSP is our core asset and primary focus. We anticipate construction of the first expansion phase at the Mine and the Upgrader to commence in the fourth quarter of 2006, subject to final investment approvals.

Steve Reynish, Executive Vice President and Chief Operating Officer

Subsequent to 2005 year-end, Chevron announced the acquisition of five leases in the Athabasca Region of northern Alberta located approximately 40 kilometres southwest of the AOSP. The leases comprise approximately 75,000 acres and could hold 7.5 billion barrels of oil-in-place based on Chevron's internal estimates. This resource has the potential for recovery using in-situ recovery methods. Under the terms of our agreement, Western has the option to participate to its 20 per cent interest in these leases. Western's option to participate may be exercised upon receiving formal notice from Chevron. Should Western elect to participate, we will be required to provide payment to our 20 per cent interest at acquisition cost.

In line with our commitment to pursue long-life hydrocarbon resources, Western acquired additional targeted lands in the Athabasca region in 2005 that may be conducive to in-situ development. The lease is comprised of approximately 8,225 acres in which Western holds a 60 per cent interest.

To manage this growing land position, we have increased our internal organizational capabilities with the addition of senior technical staff who have been instrumental in developing our long-term in-situ strategy and technical evaluations. Assessments of this nature are always made in the context of creating additional shareholder value.

Taken together, Western's rights with respect to our net undeveloped land acreage have more than doubled to 60,000 acres since the beginning of 2005. The table on the right summarizes the land position Western has access to, and the interests we will have, in the development of these leases, should they be included in our future development plans.

The leases acquired by the Joint Venture Owners in 2005 and early 2006, and to a large extent Lease 17, have not been fully evaluated. An extensive core hole drilling program will be conducted over the next several years to more fully evaluate the resource potential on these leases. As Western continues to grow, the future development of these resources has the potential to provide for substantial growth opportunities in our proved and probable reserve base.

Land Position	*Gross Area (acres)*	*Net Area to Western (acres)*	*Western Interest (%)*
AOSP/Expansions			
Lease 13	49,872	9,974	20
Lease 88	28,108	5,622	20
Lease 89	14,765	2,953	20
Lease 90	2,881	576	20
Lease 9	14,896	2,979	20
Lease 17	21,508	4,302	20
	132,030	**26,406**	–
Additional Mineable Leases			
Lease 15	3,796	759	20
Lease 351	22,773	4,555	20
Lease 352	16,447	3,289	20
Lease 631/632	6,642	1,328	20
Lease 309	11,387	2,277	20
Lease 310	7,591	1,518	20
	68,636	**13,726**	–
In-Situ Leases			
Chevron Leases	75,000	15,000	20
Lease 353 (Western)	8,225	4,935	60
	83,225	**19,935**	–
Total	**283,891**	**60,067**	–

Production from the first expansion is expected to be brought onstream in late 2009, with full bitumen production anticipated in 2010.

Matt Meyer, Upstream Development Manager

Over the past year, there has been ongoing discussion regarding the tight labour market in the Fort McMurray area and the Joint Venture continues to actively monitor this issue. Recruitment and retention remains a top priority for the AOSP. With approval of the first expansion phase anticipated in the third quarter of 2006, the AOSP believes that it well placed in terms of labour demand. Nevertheless, the AOSP is extending its reach across the country to recruit talent, particularly skilled tradespeople, who will help deliver on the Project's ambitious growth plans. The Joint Venture continues to work with regional associations and governments to attract skilled workers and mitigate infrastructure concerns in the Regional Municipality of Wood Buffalo. We believe our continuous construction growth strategy offers an attractive long-term employment incentive that will appeal to skilled tradespeople and, with over 60 per cent of our capital requirements occurring in the Edmonton area, we believe we have a distinct competitive advantage.

CORPORATE DEVELOPMENT

As an entrepreneurial, growth-oriented company, Western's goal is to continue to identify opportunities that will significantly enhance shareholder value. Western's Board and management team have been working closely together to formulate and execute on our long-term strategic plan that includes technical and corporate development activities.

Across Western's Board and management team, there exist highly skilled energy industry professionals with extensive international experience and an established track record of creating value from large hydrocarbon resources. As an entrepreneurial growth-oriented company, Western will continue to leverage and capitalize on this experience to identify and capture opportunities, domestically or internationally, with large hydrocarbon resource potential, creating further value for its shareholders. We realize high-quality opportunities take time to identify, evaluate and capture and we will prudently and patiently expand our investment horizons in this area.

Recognizing the capital intensity associated with oil sands projects, Western is pursuing technology and downstream initiatives to increase production from our existing plant, reduce energy intensity and operating costs and increase the value of our product streams. Western believes technology will continue to play an important role in the heavy oil business and warrants a prudent ongoing capital investment. One technology initiative currently under consideration is gasification. Over the longer term, the goal of the AOSP is to be less dependent on natural gas. With gasification, the goal is to take the "bottom of the barrel" of heavy bitumen and convert it into synthetic gas to generate our own fuel source. Western believes these kinds of technology initiatives will enhance the value of our assets through wider margins and increased volumes.

M. Simon Hatfield, Vice President and Managing Director, Oil & Gas
John Frangos, Corporate Development

From a broader corporate standpoint, Western's strategy is to leverage our strength as a heavy oil producer to create new opportunities that are consistent with our primary goal of value creation for our shareholders.

As part of Western's business development strategy, we have put in place the necessary structure to deliver on our growth strategy. This structure includes the addition of high-level technical and managerial expertise to capitalize on our strengths.

DOWNSTREAM

Western's marketing department fulfills three fundamental roles within the organization. These include: marketing of proprietary and third-party volumes, strategic and facility guidance with market development for expansion volumes, and downstream value creation within and outside of the AOSP operation.

MARKETING OF PROPRIETARY STREAMS

The AOSP operation produces individual product streams that are derived from both bitumen and acquired feedstock. These streams may be combined with purchased blendstocks to produce saleable synthetic crude. The Premium Albian Synthetic ("PAS") and Albian Heavy Synthetic ("AHS") streams, as well as requested variations of each type, are marketed to refineries within North America. In addition to the PAS and AHS volumes, a stream consisting of one-third of our current bitumen produced volume ("LMHVGO") is sold under a long-term agreement to Shell Canada Products.

In 2005, we continued to focus on being a "full service" marketing group. Third-party transactions allowed us to supply our customers during times of operational upsets and also displaced excess refiner volumes. This allowed refiners to assess our crude oil types without having to disrupt their normal supply arrangements. Aside from actively marketing displaced volume or sourcing third-party volume, we used our position as an active shipper on most major crude oil pipeline systems to deliver crude oil to our customers as needed.

Producing specific crude oil blends to target refineries allows Western to maximize its returns. In 2005, the need arose both internally and in the market for the production of a new sour crude product. We jointly developed and introduced a new crude oil stream, Albian Vacuum Blend ("AVB"), allowing the AOSP Joint Venture to maximize the throughput of bitumen.

In addition to marketing crude oil blends, we continue to look for opportunities to increase the netback of our Upgrader byproduct streams, including sulphur. As Western continues to grow, so too will the amount of volume we will need to market. Our plans today will position us well for the future.

GUIDANCE AND MARKET DEVELOPMENT FOR EXPANSION VOLUMES

Growth plans for the AOSP are to produce over 500,000 barrels per day within the next decade. Given the critical link between crude oil production and refinery customer requirements, Western's marketing department is actively involved with the Joint Venture expansion groups. This work includes representation on the various project teams and pipeline companies as well as liaison with customers to produce, transport and deliver optimal crude types that fit with customers' needs.

VALUE CREATION

Our goal is to increase the value of our proprietary volumes. We are also working with our Joint Venture Owners to assess Upgrader configuration changes that will reduce operating costs, source third-party feedstocks as required and improve the quality of our proprietary crude oil streams. In addition, we continue to assess downstream options, including further blending and refining to suit customer requirements, that will integrate with our existing and future production. These initiatives will improve our competitive advantage.

As we move into 2006, we will continue to build on our strengths. We will foster new customer relationships and build on the competitive advantages that have set us apart from other producers and marketers. Western will remain a full participant on industry pipeline committees, which will ensure our future crude oil production volumes are represented to existing and new markets. We will continue to monitor new western Canadian production (both conventional and upgraded) initiatives and respond to new feedstock opportunities. As we continue to grow, Western is well positioned to respond to the ongoing changes in the industry, as well as meeting our customers' long-term supply requirements.

Western continues to evaluate various downstream initiatives to integrate our existing and future production and build on our competitive oil sands position.

Gerry Luft, Vice President, Downstream

Part of Western's downstream strategy includes identifying opportunities to reduce our exposure to heavy oil differentials.

HEALTH, SAFETY AND THE ENVIRONMENT

Western believes a superior health, safety and environmental performance record is something to be proud of, an important part of gaining the confidence of shareholders, customers and society at large, and an integral part of being a good corporate citizen. Our commitment to sustainable development and corporate responsibility is critical to sound operations and serves as the foundation of our strong future.

Western is committed to sustainable development, whereby we integrate economic, environmental and social considerations in our decision-making process across all business activities to address both short- and long-term needs. This commitment means creating value for our shareholders while protecting the environment, managing resources, respecting and safeguarding people, benefiting communities and working with stakeholders.

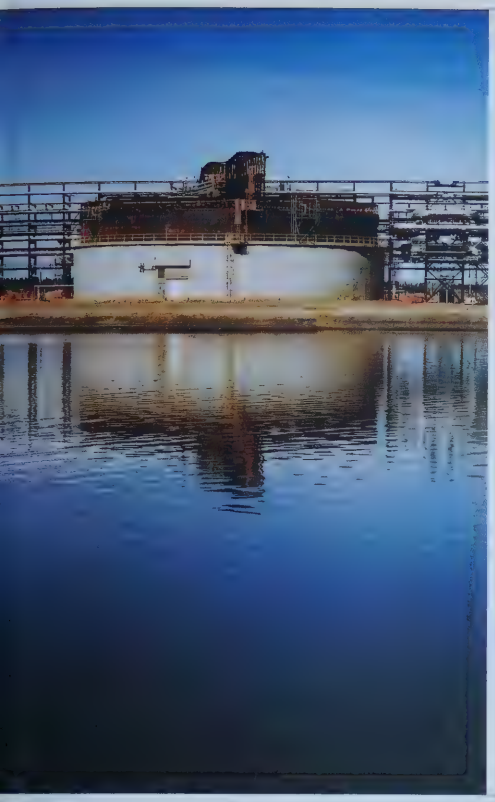
The AOSP's commitment to sustainable development is integrated throughout the Project – from design and operations through to reclamation. The Joint Venture Owners have worked diligently in the design of the original Project to ensure that environmental effects are managed and long-term effects mitigated through operations and following ultimate reclamation and closure. The AOSP continues to build on the extensive environmental assessment work completed during the original Project by identifying ways to improve energy efficiency and environmental performance.

We have implemented a voluntary greenhouse gas ("GHG") management plan. The plan is based on three components: improving energy efficiency

at the Muskeg River Mine and Scotford Upgrader, purchasing offsets and assessing the potential to capture carbon dioxide ("CO_2"). The Joint Venture is committed to developing these opportunities, and others, to meet this voluntary commitment to reduce GHG emissions.

The AOSP is investigating technologies to further reduce CO_2 emissions from its operations and has also undertaken several CO_2 capture and sequestration studies to evaluate cost-effective solutions to manage emissions.

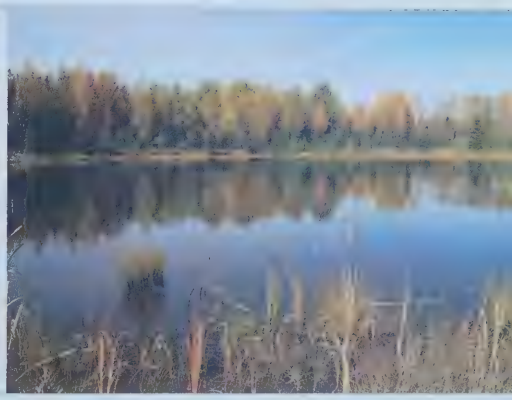
The AOSP's long-term growth plans associated with the continuous construction expansion strategy include an ongoing commitment to addressing climate change initiatives. Proven management systems will help the Project meet established environmental benchmarks as the AOSP grows. Continuing to reduce fresh water consumption, managing cumulative effects of oil sands development, and reducing GHG emissions are key objectives for the AOSP.



KEY HIGHLIGHTS DURING 2005 INCLUDE:

- Albian Sands Energy, operator of the Muskeg River Mine, reported two significant milestones in 2005. The Muskeg River Mine achieved four million hours without a lost-time incident, and the Scotford Upgrader reported two million hours without a lost-time incident.
- In June 2004, the Muskeg River Mine was certified in accordance with ISO 14001, making the AOSP the first oil sands operations in the world to be registered to this standard. In June 2005, Albian became the first company in Canada to be ISO 14001 certified under the new standards.
- At the Muskeg River Mine, an online environmental system ISO awareness computer-based learning module is helping the organization conform to the new ISO 14001 requirements.
- In 2005, the Project as a whole recorded a lost-time frequency rate of 0.4 per 200,000 hours worked and the total recordable injury frequency rate was 0.96.

Our commitment to health, safety and the environment is significant and integral to our growth plans.



COMMUNITY

The AOSP recognizes that the communities with whom we work have a significant vested interest in our Project. Part of the AOSP's commitment to sustainable development is its responsibility to members of the community. Through a variety of community investment initiatives, the AOSP works with local communities to provide skills and job training, build and support local businesses and contribute to a number of community organizations and events. In 2005, the AOSP invested over $2 million in the Regional Municipality of Wood Buffalo and the Scotford area. Specific initiatives include:

- The Project donated $750,000 to the Northern Lights Regional Health Foundation in support of Fort McMurray health care services. This contribution will assist the Foundation in purchasing a magnetic resonance imaging ("MRI") machine to provide improved diagnostic services to Fort McMurray and other communities in the Regional Municipality of Wood Buffalo.
- The AOSP demonstrated support for Keyano College's Sport and Wellness Campaign with a $250,000 donation. The contribution will be directed towards the construction of a multi-sport playing field. Keyano's new recreational centre will be a community-use complex offering state-of-the-art recreation and training facilities.

The AOSP also supports community initiatives including:

- Renovations of the YMCA of Wood Buffalo Birchwood Child Daycare and ongoing support to the Centennial Centre in Fort Saskatchewan.
- Sponsoring e-science camps and e-learning programs to a variety of northern Alberta First Nations communities.
- Supporting the Aboriginal Entrepreneurship Program at Keyano College and sponsorship of a variety of school scholarship and apprenticeship programs through NAIT, CAREERS: The Next Generation and Keyano College.

The following discussion of financial condition and results of operations was prepared as of March 28, 2006 and should be read in conjunction with the Consolidated Financial Statements and Notes thereto. It offers Management's analysis of our financial and operating results and contains certain forward-looking statements relating but not limited to our operations, anticipated financial performance, business prospects and strategies. Forward-looking information typically contains statements with words such as "anticipate", "estimate", "expect", "potential", "could", or similar words suggesting future outcomes. We caution readers and prospective investors in the Company's securities not to place undue reliance on forward-looking information as by its nature, it is based on current expectations that involve a number of assumptions, inherent risks and uncertainties, which could cause actual results to differ materially from those anticipated by Western. For a description of the risks and uncertainties facing Western, see "Outlook for 2006".

For additional information relating to the risks and uncertainties facing Western, refer to Western's Annual Information Form for the year ended December 31, 2005, which is available on SEDAR at www.sedar.com.

OVERVIEW

Western Oil Sands Inc. ("Western") owns 20 per cent of the Athabasca Oil Sands Project ("AOSP"), a multi-billion dollar Joint Venture that is exploiting the recoverable bitumen reserves and resources found in oil sands deposits in the Athabasca region of Alberta, Canada. Our partners are Shell Canada Limited ("Shell"), with a 60 per cent interest, and Chevron Canada Limited ("Chevron"), which holds the remaining 20 per cent. The AOSP consists of two key facilities: the Muskeg River Mine located 70 kilometres north of Fort McMurray, Alberta, where the oil sands deposits are mined and partially upgraded; and the Scotford Upgrader outside of Edmonton, Alberta, where the bitumen is further upgraded into synthetic crude oil and delivered into the North American crude oil marketing system. The Mine and Upgrader are connected by a 493-kilometre pipeline.

At this time, Western's 20 per cent investment in the AOSP is our most material and only operating asset. We generate revenue from the sale of our 20 per cent portion of the synthetic crude oil and other products produced at the Scotford upgrader. Approximately one-third of the volumes produced are a mixture of light, medium and heavy vacuum gas oil ("LMHVGO") that is sold to Shell under a long-term contract for use in their adjacent refinery. In addition, our processes produce two grades of synthetic crude oil: Premium Albian Synthetic ("PAS") and Albian Heavy Synthetic ("AHS"). Our share of these products is marketed and sold by Western to various refineries throughout North America.

Sustained higher commodity prices, together with greater than design production levels during 2005, combined to achieve record production, revenue, net income and cash flow from operations for Western. During the year, our capital expenditure program was financed entirely out of cash flow. Excess cash was applied to reduce our bank borrowings. Western applied $175 million to the repayment of bank credit facilities during the year, which resulted in a significant strengthening of our balance sheet. Our improving credit profile, combined with the implementation of a new strategic oil commodity risk management program, has put Western in a strong financial position to fund its share of the expansion efforts announced by the Joint Venture that will occur over the next several years.

During 2005, Western achieved successive quarterly production records from the second quarter through to the fourth quarter. In the fourth quarter of 2005, production averaged approximately 35,600 barrels per day (approximately 178,000 barrels per day at the Project level). Operational difficulties

From left to right:

Greg Phaneuf
Treasurer

David Dyck
Senior Vice President, Finance and Chief Financial Officer

Greg Stevenson
Controller

at the Upgrader in the fourth quarter of 2004 extended into the first quarter of 2005 and impacted first quarter 2005 performance. The quarterly production rates established record annual average production of approximately 32,000 barrels per day in 2005, representing an 18 per cent increase over production volumes reported in 2004. These production rates set the stage for continued operational stability and growing profitability for the AOSP's existing assets.

Reliability and availability of our existing AOSP facilities, together with on-time, on-budget execution of our AOSP expansion plans, is our primary focus. The objective is to take Western's production beyond 100,000 barrels per day over the next eight to ten years. This growth strategy also includes optimizing the value of our existing world-class assets through technological enhancements. Furthermore, as Western matures and evolves as an organization, our growth strategy includes opportunistically growing our business and leveraging our strengths by taking our core competencies and skills and applying them to new business opportunities. In this regard, one of Western's key objectives is to identify and capture large, long-life projects with significant hydrocarbon resource potential to create additional value for our shareholders.

OPERATING RESULTS

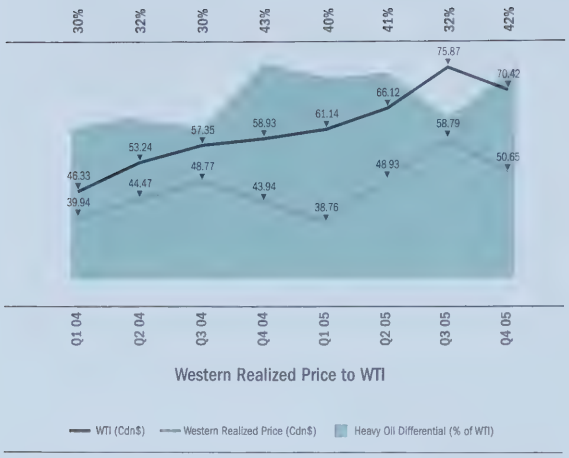
Western commenced commercial operations on June 1, 2003, which was defined by Management as attaining 50 per cent of the Project's productive design capacity of 155,000 barrels per day, with all aspects of the facilities fully operational. Since that time, Western has recorded revenues and expenses for its share of operations from the Project. Prior to June 1, 2003, all revenues, operating costs and interest were capitalized as part of the costs of the Project, and no depreciation, depletion or amortization was expensed. Comparisons to prior years' pre-operating information are provided in the following discussion where appropriate.

FINANCIAL PERFORMANCE

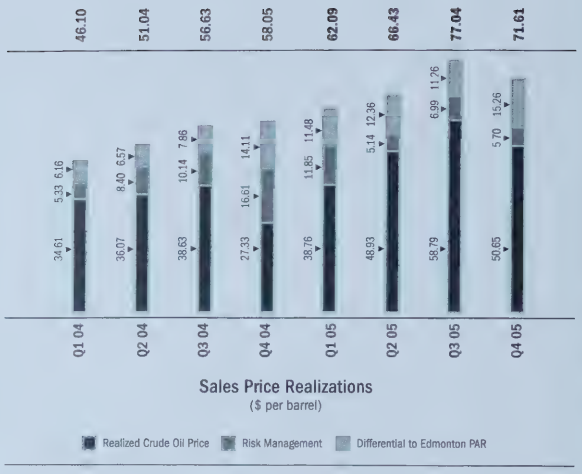
Revenue

Western achieved record gross crude oil sales revenue in fiscal 2005 totalling $910.3 million (2004 – $636.9 million), including $777.9 million (2004 – $458.5 million) from proprietary production at an average realized price of $49.91 per barrel (2004 – $34.60 per barrel). Gross revenue rose 43 per cent primarily as a result of an 18 per cent increase in production during the year, combined with a 44 per cent increase in blended price realizations. Gross revenue includes the effects of risk management activities that reduced revenue by $110.4 million (2004 – $131.4 million), and reduced the average realized price by $7.11 per barrel during 2005 (2004 – $9.92 per barrel).

Western's crude oil sales were subject to an overall quality differential of $12.27 per barrel (2004 – $8.44 per barrel) off of the Edmonton PAR benchmark crude oil price of $69.29 per barrel in 2005. Forced operational outages at the Upgrader in the first quarter of 2005 resulted in a larger percentage of heavy crude in our overall sales mix and, since these streams receive a lower price, overall sales price realizations decreased. Sales price realizations during 2005 were also negatively impacted by a widening of the heavy oil differential to West Texas Intermediate ("WTI") compared to 2004. The heavy oil differential to WTI widened to an average 39 per cent during 2005 compared to an average of 34 per cent in 2004, and has historically represented approximately 30 per cent of stated posted WTI prices. As the graph on page 24 indicates, Western's sales price realizations are largely correlated to movements in WTI. Over the last two years, the only quarters where this relationship was not maintained was during the fourth quarter of 2004 and first quarter of 2005, where forced operational outages occurred, resulting in Western's sales mix skewed to a greater proportion of heavy crude oil.



Western Realized Price to WTI



Sales Price Realizations
($ per barrel)

The AOSP is actively identifying optimization initiatives to reduce the Project's exposure to heavy oil price differentials. We have observed that the heavy oil differential to WTI tends to increase as WTI itself appreciates. If this relationship continues, we would expect heavy oil differentials to remain wide in periods of robust commodity prices. Western expects its sales price realizations to improve in 2006 largely due to the absence of any fixed-price hedges, which ended in December 2005, allowing Western to fully participate in actual crude oil prices during the upcoming year. In total, Western's fixed price hedging program, which commenced during 2003, reduced revenue by approximately $250 million. These hedges were executed in late 2002 and

Highlights	***2005***	*2004*	*2003*
Operating Data *(bbls/d)*			
Bitumen Production	**31,994**	27,108	23,596
Synthetic Crude Sales	**42,534**	36,210	32,207
Operating Expense per Processed Barrel *($/bbl)*	**22.06**	21.17	20.71
Financial Data *($ thousands, except as indicated)*			
Gross Revenue	**910,330**	636,911	281,093
Realized Crude Oil Sales Price – Oil Sands *($/bbl)* (1) (2)	**49.91**	34.60	32.81
Cash Flow from Operations (3)	**244,231**	23,044	5,803
Cash Flow per Share – Basic *($/Share)* (1) (4)	**1.52**	0.15	0.04
Net Earnings Attributable to Common Shareholders (6)	**149,449**	19,452	15,003
Net Earnings per Share *($/Share)*			
Basic	**0.93**	0.12	0.10
Diluted	**0.92**	0.12	0.10
EBITDAX (1) (5)	**307,008**	87,587	47,615
Net Capital Expenditures (7)	**46,833**	39,968	148,473
Total Assets	**1,590,520**	1,470,870	1,458,424
Long-Term Debt	**565,655**	662,620	860,580
Long-Term Financial Liabilities (8)	**706,880**	716,094	914,773
Weighted Average Shares Outstanding – Basic *(Shares)*	**160,169,887**	156,926,514	151,032,996

(1) Please refer to page 44 for a discussion of non-GAAP financial measures.

(2) The realized crude oil sales price is the revenue derived from the sale of Western's share of the Project's synthetic crude oil, net of the risk management activities, divided by the corresponding volume. Please refer to page 25 for calculation.

(3) Cash flow from operations is expressed before changes in non-cash working capital.

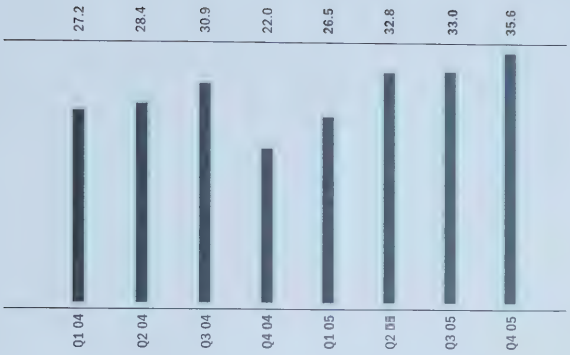
(4) Cash flow per share is calculated as cash flow from operations divided by weighted average common shares outstanding, basic.

(5) Earnings before interest, taxes, depreciation, depletion, amortization, stock based compensation, accretion on asset retirement obligation, foreign exchange and risk management as calculated on page 34.

(6) Western has not paid cash dividends in any of the above referenced fiscal years.

(7) Net capital expenditures are capital expenditures net of any insurance proceeds received during the period.

(8) Long-term financial liabilities includes long-term debt, option premium liability and lease obligations. Prior years are restated to include lease obligations.



Quarterly Production Volumes
(thousands of bbls)

over the course of fiscal 2003 during a significantly lower crude oil price regime. The hedging program (which locked-in a fixed WTI price on Western's share of production from the AOSP ranging from 20,000 barrels per day down to 7,000 barrels per day at its completion in the last quarter of 2005) provided a base line level of cash flow to meet future debt servicing and working capital commitments and protected the Company from a precipitous drop in oil prices.

As detailed in the "Financial Risks" section, Western completed a separate strategic crude oil risk management program during the third quarter of 2005 covering a portion of our production from 2007 through to the end of 2009. The put/call "collar" structure employed establishes a floor price for up to two-thirds of our expected production, yet allows for participation in increasing oil prices during this period and, thereby, does not limit the upside potential related to commodity price appreciation to the same degree as the fixed-price swap contracts used previously.

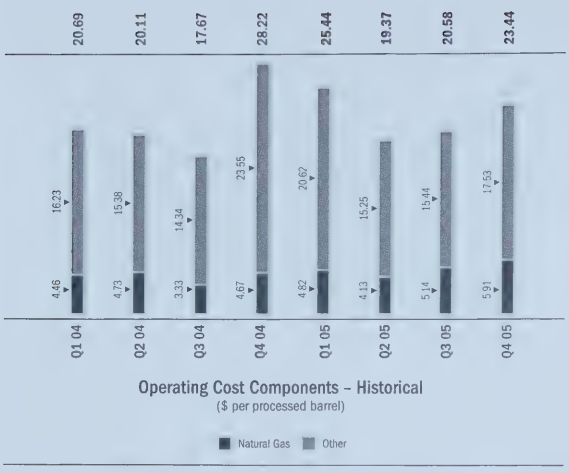
Western generated net revenue of $591.4 million in 2005 compared to $321.0 million in 2004, representing an 84 per cent increase. Net revenue reflects the costs of purchased feedstocks and transportation costs downstream of Edmonton. Feedstocks are crude oil products introduced at the Upgrader. Some feedstocks are introduced into the hydrocracking/hydrotreating process and others are used as blendstock to create various qualities of synthetic crude oil products. The cost of these feedstocks depends on world oil markets and the spread between heavy and light crude oil prices.

Net Revenue
($ thousands, except as indicated)

	2005	2004
Revenue		
Oil Sands [1]	**777,876**	458,502
Marketing and Transportation	**132,454**	178,409
Total Revenue	**910,330**	636,911
Purchased Feedstocks and Transportation		
Oil Sands	**185,693**	137,810
Marketing and Transportation	**133,241**	178,116
Total Purchased Feedstocks and Transportation	**318,934**	315,926
Net Revenue		
Oil Sands [1]	**592,183**	320,692
Marketing and Transportation	**(787)**	293
Total Net Revenue	**591,396**	320,985
Synthetic Crude Sales *(bbls/d)*	**42,534**	36,210
Crude Oil Sales Price *($/bbl)* [2]	**49.91**	34.60

(1) Oil sands revenue and net revenue are presented net of Western's hedging activities.

(2) Realized crude oil sales price ($/bbl) is calculated as oil sands revenue less any transportation costs divided by synthetic crude sales volume. For the year ended 2005, $3.0 million (2004 – nil) had been incurred for transportation costs related to oil sands.



Operating Costs

We believe that, to a certain extent, our operating costs are a function of longer-term WTI prices. In 2005, WTI averaged US$56.56 per barrel, which put upward pressure on certain cost components, including natural gas. Operating costs for oil sands operations typically decline over time as the technological and engineering challenges are addressed and resolved and as efficiency and effectiveness programs are completed. These efficiencies are being realized at the AOSP, and we expect to see a continued reduction in unit operating costs over the coming years; however, this may be offset by continued increases in the cost of natural gas and of basic materials and supplies caused by major demand pull in critical supply markets and variations in the ore body with respect to bitumen grade and strip ratio (ore to waste). Given our state-of-the-art technology, and what we assess as a superior ore body, we believe Western can be one of the lowest-cost producers of synthetic crude oil in the Canadian oil sands.

Western's share of Project operating costs totalled $250.4 million in 2005 (2004 – $213.0 million). Included in this total are the costs associated with removing overburden at the Mine and transporting bitumen from the Mine to the Upgrader. On a per processed barrel of bitumen basis, unit operating costs were $22.06 per barrel based on average production of 31,994 barrels per day in 2005 compared to $21.17 per barrel based on average production of 27,108 barrels per day in 2004.

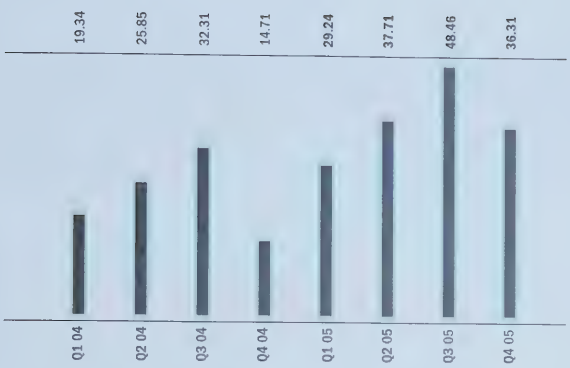
Higher unit operating costs in 2005 were largely due to increasing natural gas costs for fuel, utilities and hydrogen supply as well as higher input costs for materials and supplies in an escalating commodity price environment. Natural gas costs per unit increased 19 per cent over 2004 as a result of higher underlying gas prices. We also observed higher prices for supplies and materials and contract services as a result of the heated commodity environment, as these suppliers were themselves experiencing higher demand for their goods and services leading to higher costs. Unit operating costs in 2005 were also impacted by repair costs incurred in the first quarter, stemming from the forced operational outages that commenced in the fourth quarter of 2004 and extended into the first quarter of 2005. Unit

Operating Costs

($ thousands, except as indicated)

	2005	2004
Operating Expenses for Bitumen Sold		
Operating Expense – Income Statement	**250,389**	212,993
Operating Expense – (Inventoried)/Expensed in Purchased Feedstocks	**11,704**	(3,058)
Total Operating Expenses for Bitumen Sold	**262,093**	209,935
Sales *(barrels per day)*		
Total Synthetic Crude Sales	**42,534**	36,210
Purchased Upgrader Blendstocks	**9,979**	9,112
Synthetic Crude Sales Excluding Blendstocks	**32,555**	27,098
Operating Expenses per Processed Barrel *($/bbl)* (1)	**22.06**	21.17

(1) Operating expenses per processed barrel ($/bbl) is calculated as total operating expenses for bitumen sold divided by synthetic crude sales excluding blendstocks. This calculation recognizes that, intrinsic in the Project's operations, bitumen production from the Mine receives an approximate three per cent uplift as a result of the hydrotreating/hydroconversion process, which is included in synthetic crude sales excluding blendstocks.



Netback per Barrel Produced Excluding Hedges
($ per barrel bitumen produced)

operating costs per processed barrel of bitumen were $25.44 per barrel in the first quarter of 2005. Over the next three successive quarters, where the Project achieved record production levels, unit operating costs averaged $21.22 per processed barrel of bitumen, of which $5.10 per barrel relates to natural gas.

Operating costs are, and will continue to be, a key metric among companies active in the mineable oil sands industry. Companies that control costs will drive better financial results. Different oil sands producers have different cost structures and accounting treatments that require careful analysis to make meaningful comparisons. Western, for example, includes the cost of transporting processed bitumen from Fort McMurray to Edmonton as part of overall operating costs, whereas other industry players net these transportation costs from oil sands revenue. Western also includes in its operating costs the cost to remove the overburden in its mining operations, while some other oil sands producers capitalize such costs. Nevertheless, all companies active in the energy industry are coming to terms with the higher commodity price environment and associated increased costs for materials, supplies and natural gas. Even though the entire industry cost structure has shifted upwards, Western will continue to evaluate all methods to control and reduce its cost structure. As the majority of the AOSP's operating costs are fixed, to the extent the Project can maintain continuous reliable operations, total unit operating costs will decrease as the costs are spread out over a greater production base.

Operating Netbacks

Despite the forced operational outages experienced in the fourth quarter of 2004 that extended into the first quarter of 2005, Western achieved a robust netback per barrel excluding commodity hedge impacts, compared to previous quarters. Heavy oil differentials widened towards the end of the year and, combined with the continued strength in the US/Cdn exchange rate, put pressure on our fourth quarter results. The heavy oil differential widened in part due to the seasonal reduction in demand by refineries as they undertake year-end maintenance programs. We expect to achieve materially higher netbacks in 2006 due to the expiration of our fixed-priced swap hedging program on December 31, 2005, assuming that commodity prices maintain current levels. Hedging losses of $110.4 million in 2005 materially decreased Western's netbacks.

Royalties

Royalties amounted to $4.0 million or $0.34 per barrel of bitumen in 2005 compared to $3.0 million or $0.30 per barrel of bitumen in 2004. Higher gross royalties reflect record production levels in 2005, together with a higher deemed bitumen price, the latter of which serves as the basis for the royalty calculation. Initially, royalties are calculated at one per cent of the gross revenue from the bitumen produced (based on its deemed value prior to upgrading) until recovery of all capital costs associated with the Muskeg River Mine and Extraction Plant, together with a return on capital equal to the Government of Canada's federal long-term bond rate. After full capital cost recovery, the royalty is calculated as the greater of one per cent of the gross revenue on the bitumen produced or 25 per cent of the net revenue on the bitumen produced. Western fully expects to participate in the expansions of the AOSP. As such, Western anticipates that additional capital incurred to construct the expansions will be added to the capital base for royalty purposes. Western believes certain capital relating to the extraction of bitumen will be "ring-fenced" for royalty purposes, which, in turn, will extend our royalty horizon. Assuming a long-term WTI price of US$55.00 to US$60.00 and a US/Cdn exchange rate of $0.85, we estimate our royalty horizon on the Project to be approximately 2010, after which we will be paying royalties at the higher rates. The royalty horizon may be accelerated or postponed depending on future prices of crude oil, foreign exchange rates and the timing and inclusion of capital expenditures.

RESERVES, RESOURCES AND LAND

Under the terms of the Joint Venture Agreement for the AOSP, Western and its Joint Venture Participants have in place a Participation and Area of Mutual Interest Agreement ("AMI"). The AMI stipulates that the Project Owners have rights to participate in any additional leases that are acquired by any one of the Joint Venture Participants in the Athabasca region.

Within the Project we have the following: proved and probable reserves that are associated with the existing operations at the Muskeg River Mine; resources on lands within the Joint Venture that have been evaluated; and finally, undeveloped lands which have been acquired by all three Owners during the past year that are included under the terms of the AMI and are subject to evaluation for possible future development.

Reserves

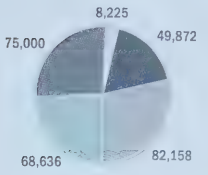
GLJ Petroleum Consultants Ltd. ("GLJ") has independently estimated that the proved and probable reserves on the west side of Lease 13 are 1.6 billion barrels (310 million barrels net to Western). These proved and probable reserves translate into a reserve life index of approximately 27 years based on an anticipated undiluted bitumen production rate of 155,000 barrels per day (31,000 barrels per day net to Western). Substantial reserve additions will be made as the AOSP moves through the gating process for the upcoming phases of expansion. Resources from our future expansions will be booked as reserves when the expansion phases are permitted, funding is approved and certain stipulations pursuant to the Joint Venture Agreement are satisfied. The table below summarizes the Project's reserves and our share of those proved and probable reserves as at December 31, 2005 on a synthetic crude oil basis utilizing GLJ's forecast of escalating prices and costs. Synthetic crude

Reserves Summary

	Gross Project Reserves (MMbbls)	Working Interest Reserves (MMbbls)	Net After Royalty (MMbbls)	Present Value of Estimated Future Net Cash Flow before Income Taxes 0% ($ millions)	10% ($ millions)	15% ($ millions)	20% ($ millions)
Proved	974	195	179	3,650	2,014	1,611	1,337
Probable	577	115	104	2,799	671	386	248
Proved Plus Probable	1,551	310	283	6,449	2,685	1,997	1,585

Reserves Reconciliation (Working Interest)
(MMbbls)

	Proved	Proved Plus Probable
December 31, 2004	204	317
Production	(12)	(12)
Revisions	3	5
December 31, 2005	**195**	**310**



283,891 acres

Joint Venture Land Position
(acres)

- Lease 13
- Shell Leases (pre-2005)
- Shell Leases (acquired in 2005)
- Chevron Leases
- Western Lease

oil is dry bitumen, uplifted by three per cent for hydrocracking/hydrotreating.

The following information relating to our reserves and present values of estimated future net cash flow constitutes forward-looking statements as it is based upon assumptions relating to, among others, volumes of oil in place, recoverability of bitumen, production rates, royalty rates, operating and development costs, capital expenditures, commodity prices and foreign exchange rates. For a description of the risks and uncertainties facing Western that could impact on the volume and value of the reserves reported below, see "Outlook for 2006".

Resources

The AOSP has several leases that have been formally evaluated for resource potential. These are Leases 88, 89, 90, 9 and 17 and the remainder of Lease 13. Western engaged Norwest Corporation ("Norwest") to conduct this assessment. They provided high, best and low estimates of discovered resources for each area, with the exception of Lease 17 which only includes a high estimate. The best case estimate for the discovered resources on a total AOSP basis exceeds 8.2 billion barrels in place or 1.6 billion barrels net to Western. Except in the case of Lease 17 where data is limited, Norwest's report is based on several critical assumptions in order to record resources-in-place, namely, minimum bitumen by weight of seven per cent to total weight, minimum mining thickness of three metres and maximum total volume to bitumen in place ("TV:BIP") of 12:1. The details of the specific leases are summarized in the table below.

Undeveloped Land

During 2005, Shell acquired additional mineable oil sands acreage including leases 15, 309, 310, 351, 352, 631 and 632. These leases were acquired through public land auctions held by the Government of Alberta. Pursuant to the AMI, Western has rights to participate to a 20 per cent interest in the development of these leases.

A second addition to the undeveloped land base are five heavy oil leases recently purchased by Chevron. It is believed these leases would be amenable to extract bitumen through in-situ recovery methods. Western has the right to participate

Estimate of Discovered Resources *(1) (2)* *(MMbbls in place)*	*High (P90)*	*Best (P50)*	*Low (P10)*
Remainder of Lease 13	5,251	5,028	3,194
Lease 90	269	253	162
Leases 88 and 89	2,382	2,038	856
Lease 9 and 17 *(3)*	2,110	899	431
Total	10,012	8,218	4,643

(1) The table above represents total Project interest in the leases which are currently held by Shell. Under the AMI, Western has the right to participate in these leases to a 20 per cent level.

(2) "Discovered Resources" are those quantities of oil and gas estimated on a given date to be remaining in, plus those quantities already produced from, known accumulations. Discovered resources are divided into economic and uneconomic categories, with the estimated future recoverable portion classified as reserves and contingent resources, respectively. (Source: Canadian Oil and Gas Evaluation Handbook, Volume 1, Section 5.2.2.)

(3) Norwest attributed only inferred resources to Lease 17 (high estimate only) reflecting a probability of only 10 per cent that the resource equals or exceeds the estimated amount given the limited amount of data available on this lease. Major assumptions used in the classification of inferred resources for Lease 17 were average in-place bitumen content of 10 per cent to total weight and ore thickness of approximately 15 metres over less than half the lease area. Due to the level of uncertainty on this lease, it should not be assumed that all or any part of an inferred resource will be upgraded as a result of continued exploration.

to a 20 per cent undivided interest in these leases. Our right may be exercised upon Chevron providing us with formal notice of the purchase, followed by our response within 60 days of that notice regarding our intent to participate, together with the applicable payment.

A further addition to this already extensive land position is Lease 353, which Western itself acquired during 2005, representing 8,225 acres. This lease is also considered in-situ in nature. Western holds a 60 per cent interest in this lease as both Shell and Chevron have elected to participate to a 20 per cent interest. Western significantly increased its internal organizational capabilities in 2004 and 2005 by adding senior technical staff to develop our in-situ strategy.

Combining all of the leases under the AMI, the acreage position in the Athabasca region now approaches 284,000 acres (60,000 acres net to Western), more than doubling the land base compared to 2004. Of this total, approximately 71 per cent represents mineable leases, with the remaining 29 per cent considered in-situ. The leases recently acquired by all Joint Venture partners have not yet been evaluated for resource potential; however, several are located adjacent to leases where resource evaluations have been conducted. An extensive core-hole drilling program will be conducted over the next several years on all of the newly acquired leases to evaluate the resource potential. The leases recently acquired by Shell could potentially be developed as an extension to the AOSP's continuous construction expansion strategy.

The exploration and development of this significant land base, both mineable and in-situ, could involve a substantial and material capital commitment on the part of Western to maintain our rights. Assessments regarding Western's involvement are always made in the context of maintaining the integrity of our financial position and creating shareholder value.

CORPORATE RESULTS

Research and Business Development

A small portion of Western's capital budget is directed to new business development activities. These activities include: research and development efforts with the objective of identifying ways to add value to our existing assets; the addition of some internal technical capabilities in order to evaluate opportunities as they arise either through our Joint Venture partners or independently; and finally, as part of Western's long-range strategy, plans include expanding our organizational capabilities to evaluate business opportunities, domestically or internationally, by taking our core competencies and skills and applying them to new ventures that represent long-life projects with significant hydrocarbon resource potential. Western incurred $10.7 million for research and business development expenses in 2005, of which $5.0 million relates specifically to AOSP-related research projects. In 2004, Western recorded $4.7 million for research and business development, which related entirely to the impairment of a previously capitalized research project. Amounts are higher compared to the prior year period as Western continues to add significant technical and professional staff to source and investigate business development activities.

General and Administrative Expenses

General and administrative expenses ("G&A") were $11.3 million in 2005 or $0.97 per barrel compared to $8.1 million or $0.82 per barrel in 2004. The increase is largely a function of Western analyzing certain business development activities that result in higher levels of professional and legal fees, travel and other corporate expenses that arise in conducting these evaluations. It also reflects additional professional costs incurred during 2005 due to increased public company compliance requirements compared to 2004.

Interest Expense per Barrel Produced
($/bbl)

Interest Coverage
(times)

Insurance Expenses

Insurance expenses were $8.0 million in 2005 compared to $9.4 million in 2004. Western maintains insurance policies covering property damage, business interruption, commercial general liability and directors and officers liability, in addition to various corporate policies. Insurance expense in 2005 is lower than the previous year due to a reduction in the premiums associated with our policies and the strengthening of the Cdn/US exchange rate as these premiums are paid in US dollars. There were no material modifications in coverage compared to the prior year.

We are expecting insurance expenses to increase in 2006 as a result of higher limits on such policies as business interruption, together with increased premiums charged by insurance carriers on our corporate policies, given worldwide events in the insurance marketplace.

Interest Expense

During 2005, total interest charges were $58.2 million, $3.0 million lower than 2004. The 2005 expense of $58.2 million is comprised of $54.3 million related to interest charges on our debt obligations (2004 – $59.1 million), $2.6 million (2004 – $2.0 million) on our capital lease obligations and $1.3 million (2004 – $nil) on our option premium liability. The option premium liability relates to Western's new strategic crude oil risk management program implemented in the third quarter of 2005 and the decision to defer the premiums associated with the put and call options purchased and sold, respectively. Imbedded in the prices of the deferred options is a financing charge that is reported as interest expense.

Western's debt obligations include US$450 million Senior Secured Notes and a $340 million Revolving Credit Facility. The average percentage cost of our debt increased over last year due to Western aggressively repaying debt under its Revolving Credit Facility. As this debt is priced at a lower interest rate, the average overall interest rate will increase since the Senior Notes represent a larger percentage of the outstanding debt. The Notes bear interest at 8.375 per cent and are not callable before their maturity date of May 1, 2012. Western's ability to meet fixed debt servicing costs continues to improve which can be measured by the interest coverage ratio. This ratio has improved nearly seven-fold over the last two years, when initially Western's leverage was significantly higher than at the end of 2005. Interest expense on a per barrel basis has also decreased as debt is repaid and production achieves sustained rates meeting or exceeding design specifications.

The table on page 32 summarizes our interest expense and average cost of debt for the past two fiscal years.

Depreciation, Depletion and Amortization

In 2005, Western recorded $50.7 million as depreciation, depletion and amortization expense compared to $44.5 million in 2004. Depletion is calculated on a unit of production basis for our share of Project capital costs, while previously deferred financing charges are amortized on a straight-line basis over the remaining life of the debt facilities. The increase for 2005 is primarily a result of an 18 per cent increase in production in 2005 versus 2004.

Foreign Exchange

In 2005, WTI averaged US$56.56 per barrel compared to US$41.40 per barrel in 2004, representing a 37 per cent increase. This significant appreciation in the commodity price was offset somewhat by a strengthening in the Canadian dollar relative to the US dollar. For Western, the negative impact of the foreign exchange rate increase on revenue was somewhat offset by lower interest costs expressed in Canadian dollars on our US dollar denominated Senior Secured Notes and a reduced liability (as measured in Canadian dollars) associated with this debt. In 2005, Western recorded an unrealized foreign exchange gain of $17.0 million compared to a gain of $40.0 million in 2004

Unrealized FX Gain (Loss) vs. FX Rate

relating to the conversion of the Senior Secured Notes to Canadian dollars. As reference points, the noon-day closing foreign exchange rate on December 31, 2005 was $0.8577 US/Cdn compared to $0.8308 US/Cdn on December 31, 2004. In terms of average noon-day rates for the respective periods, fiscal 2005 was $0.8254 US/Cdn compared to $0.7683 US/Cdn for fiscal 2004.

Income Taxes

Western has sizeable tax pools totalling $1.4 billion that were accumulated in conjunction with our 20 per cent share of the construction costs for the Muskeg River Mine and Extraction Plant and the Scotford Upgrader. These tax pools will be used to offset future taxable income and extend the time horizon before we pay cash taxes.

Interest and Long-Term Debt Financing

($ thousands, except as indicated)

	2005	2004
Interest Expense		
Interest Expense on Long-Term Debt	**54,324**	59,118 (2)
Interest on Obligations under Capital Lease	**2,562**	2,036
Interest on Option Premium Liability	**1,279**	–
Total Interest Expense	**58,165**	61,154
Long-Term Debt Financing		
US$450 Million Senior Secured Notes (1)	**524,655**	541,620
Revolving and Senior Credit Facilities	**41,000**	216,000 (2)
Total Long-Term Debt	**565,655**	757,620
Average Long-Term Debt Level	**661,638**	809,100
Average Cost of Long-Term Debt (3)	**8.21%**	7.31%

(1) Under Canadian GAAP, the Senior Secured Notes are recorded in Canadian dollars at exchange rates in effect at each balance sheet date. Unrealized foreign exchange gains or losses are then included on the Consolidated Statement of Operations.

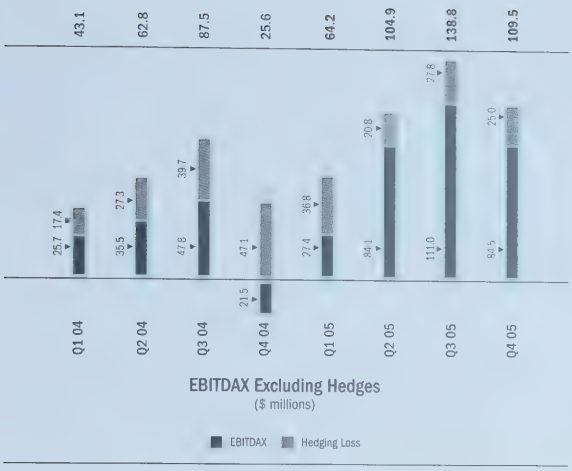
(2) For comparative purposes, amounts include the $95 million principal outstanding under the $100 million Senior Credit Facility, which is classified for accounting purposes as short-term liabilities pursuant to its maturity on April 23, 2005.

(3) Calculated by dividing the interest expense on long-term debt by the average long-term debt balance outstanding during the year.

Depreciation, Depletion & Amortization

Year ended December 31

	2005		2004	
	($ thousands)	*$/bbl*	*($ thousands)*	*$/bbl*
Depreciation and Depletion	**48,206**	**4.13**	41,933	4.23
Amortization	**2,532**	**0.22**	2,582	0.26
Total Depreciation, Depletion and Amortization	**50,738**	**4.35**	44,515	4.49



For the year ended December 31, 2005, Western recorded a future income tax liability of $56.4 million compared to a future income tax asset of $14.5 million at December 31, 2004. Western recognized approximately $71.0 million of future income tax expense during the year as we had record profitability in 2005. During 2005, we expensed $3.0 million (2004 – $1.7 million) with respect to the Large Corporations Tax. No other current taxes are payable and Western's cash tax horizon is estimated to be 2010 given a long-term WTI price of US$55.00 to US$60.00 and a US/Cdn foreign exchange rate of $0.85. Western's forecasted cash tax horizon is predicated on the successful execution of the AOSP expansion initiatives that would see gross AOSP production exceed 500,000 barrels per day.

Commencing in the latter part of 2005, discussions were held between the AOSP and the Canada Revenue Agency ("CRA") regarding the proper characterization of certain expenditures included in the Canadian exploration expenses in those years. These discussions may result in a change to the treatment of certain expenditures renounced pursuant to Western's flow-through share offerings in prior years. Refer to the section titled "Flow-Through Shares" and Western's financial statements (Note 19).

Net Earnings

Net earnings increased seven-fold, reaching $149.4 million ($0.93 per share) in 2005, compared to $19.5 million ($0.12 per share) in 2004. Earnings for the year reflect $17.0 million ($14.1 million net of tax) of unrealized foreign exchange gains on our US$450 million Senior Secured Notes, a $13.5 million ($9.1 million net of tax) unrealized gain on risk management activities and a future income tax expense of $71.0 million. Earnings before interest, taxes, depreciation, depletion and amortization, stock-based compensation, accretion on asset retirement obligation, foreign exchange gains and risk management gains were $307.0 million. Cash flow from operations, before changes in non-cash working capital, was $244.2 million ($1.52 per share) in 2005 compared to $23.0 million ($0.15 per share) in 2004. Excluding the negative impact of fixed-price crude swaps, earnings and cash flow from operations would have been $259.8 million and $354.6 million, respectively. Robust commodity prices, together with sustained reliable operations over the course of the year, resulted in a new annual record for EBITDAX for Western. Excluding the negative impact of the fixed-price crude swaps, EBITDAX would have equalled $417.4 million. Western's fixed price hedging program expired

Tax Pools

December 31 ($ thousands)	*2005*	*2004*
Canadian Exploration Expense	**89,140**	141,327
Canadian Development Expense	**23,657**	33,795
Canadian Exploration and Development Overhead Expense	**–**	–
Cumulative Eligible Capital	**7,925**	7,479
Capital Cost Allowance	**126,001**	89,194
Accelerated Capital Cost Allowance	**1,090,155**	1,087,056
Total Depreciable Tax Pools	**1,336,878**	1,358,851
Loss Carry Forwards	**14,000**	163,740
Financing and Share Issue Costs	**9,596**	15,130
Total Tax Pools	**1,360,474**	1,537,721

at the end of fiscal 2005 and, therefore, Western will participate to a greater extent in actual commodity prices than it experienced in 2004 and 2005 should prices remain at these levels.

The table below provides the reconciliation between net earnings attributable to common shareholders, cash flow from operations (before changes in non-cash working capital) and EBITDAX.

Reconciliation: Net Earnings to EBITDAX
December 31 ($ thousands)

	2005	*2004*	*2003*
			(restated)
Net Earnings Attributable to Common Shareholders	**149,449**	19,452	15,003
Add (Deduct):			
Depreciation, Depletion and Amortization	**50,738**	44,515	27,531
Accretion on Asset Retirement Obligation	**562**	471	471
Stock-Based Compensation	**3,149**	967	278
Impairment of Long-lived Assets	**–**	4,733	–
Unrealized Foreign Exchange Gain	**(17,803)**	(39,960)	(35,280)
Unrealized Risk Management Gain	**(13,450)**	–	–
Future Income Tax Expense (Recovery)	**70,956**	(7,104)	(4,330)
Interest Expense on Option Premium Liability	**1,278**	–	–
Charge for Convertible Notes	**–**	–	2,130
Cash Settlement on Asset Retirement Obligations	**(52)**	–	–
Cash Settlement on Performance Share Units	**(596)**	(30)	–
Cash Flow from Operations, before Changes in Non-Cash Working Capital	**244,231**	23,044	5,803
Add (Deduct):			
Interest (excluding interest on Option Premium Liability)	**56,887**	61,154	38,429
Realized Foreign Exchange Loss	**2,242**	1,610	304
Large Corporations Tax	**3,000**	1,749	3,079
Cash Settlement on Asset Retirement Obligations	**52**	–	–
Cash Settlement on Performance Share Units	**596**	30	–
EBITDAX	**307,008**	87,587	47,615

Please refer to page 44 for a discussion of non-GAAP financial measures.

Quarterly Information

The following table summarizes key financial information on a quarterly basis for the last two fiscal years.

Quarterly Information

($ millions, except per share amounts)	*Q1*	*Q2*	*Q3*	*Q4*	*Total*
2005					
Net Revenue	**91.7**	**148.2**	**185.7**	**165.8**	**591.4**
Capital Expenditures, Net	**17.5**	**(12.9)**	**16.0**	**26.2**	**46.8**
Long-Term Debt	**773.3**	**755.5**	**597.5**	**565.7**	**565.7**
Cash Flow from Operations (1)	**10.8**	**68.0**	**95.0**	**70.4**	**244.2**
Cash Flow per Share (2) (5) (6)	**0.07**	**0.42**	**0.59**	**0.44**	**1.52**
Earnings (Loss) Attributable to Common Shareholders (3) (4)	**(1.9)**	**28.7**	**79.3**	**43.3**	**149.4**
Earnings (Loss) per Share – Basic (3) (6)	**(0.01)**	**0.18**	**0.50**	**0.27**	**0.93**
– Diluted (3) (6)	**(0.01)**	**0.18**	**0.49**	**0.27**	**0.92**
2004					
Net Revenue	82.7	93.3	104.1	40.9	321.0
Capital Expenditures, Net	5.5	7.3	13.5	13.8	40.0
Long-term Debt	852.7	715.2	638.8	662.6	662.6
Cash Flow from Operations (1)	9.0	19.4	32.5	(37.9)	23.0
Cash Flow per Share (2) (5) (6)	0.06	0.12	0.21	(0.24)	0.15
Earnings (Loss) Attributable to Common Shareholders	(5.7)	(9.2)	42.4	(8.0)	19.5
Earnings (Loss) per Share – Basic (6)	(0.04)	(0.06)	0.27	(0.05)	0.12
– Diluted (6)	(0.04)	(0.06)	0.26	(0.05)	0.12

(1) Cash flow from operations is expressed before changes in non-cash working capital.

(2) Cash flow per share is calculated as cash flow from operations divided by weighted average common shares outstanding, basic. 2004 amounts restated to reflect 3:1 share split effected in May 2005.

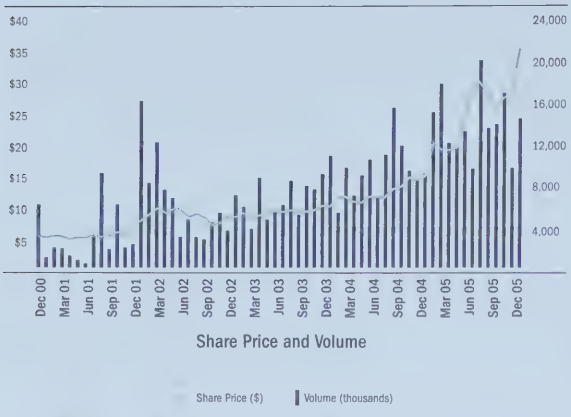
(3) Includes unrealized foreign exchange gains (losses) on US$450 million Senior Secured Notes and Option Premium Liability: (Q1 (loss) – $2.7 million, Q2 (loss) – $7.2 million, Q3 – $30.2 million, Q4 (loss) – $2.5 million).

(4) Includes unrealized risk management gains (losses) on strategic crude oil program (Q1 – nil; Q2 – nil; Q3 – $1.7 million; Q4 – $11.8 million).

(5) Please refer to page 44 for a discussion of non-GAAP financial measures.

(6) Per share amounts pre-May 2005 have been restated to reflect 3:1 share split effective May 30, 2005. Total amounts may not add due to rounding.

Rate of Return	2001	2002	2003	2004	2005	Compounded
	27%	27%	22%	42%	99%	42.4%



Share Price and Volume

Debt/Book Capitalization
(%)

A $100 investment was worth $585 at the end of December 2005.

LIQUIDITY AND FINANCIAL POSITION

Western's liquidity and financial position has strengthened significantly since its inception. In particular, 2005 represented a record year in terms of production, earnings and cash flow. Cash flow from operations was used to fund all of our capital expenditures during 2005. Excess cash flow of $197 million was primarily applied to repay bank credit facilities. As a result, Western's overall debt to capitalization ratio has improved substantially. At year-end 2005, this ratio was 50 per cent, down from its high of 66 per cent at the end of 2003. The implementation of a strategic crude oil risk management program announced in the third quarter of 2005, covering fiscal years 2007 through to 2009, will provide certainty of cash flow during this time period to provide the funding of a majority of our expansion capital needs in light of upcoming capital expenditures associated with the first of multiple phases of expansion of the AOSP. Incremental debt may be required to fund future expansion phases and other new business development initiatives as they arise.

Debt Financing

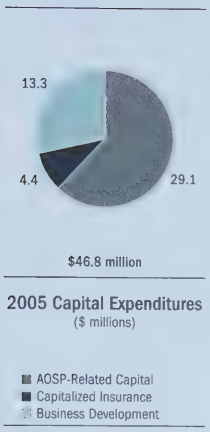
In 2005, we maintained our US$450 million of Senior Secured Notes as they are non-callable with a maturity of May 1, 2012. We were also successful in making two amendments to our bank credit facilities. First, in March 2005, we amended the $240 million Revolving Credit Facility (the "$240 million Revolver") to consolidate its commitments and the $100 million Senior Credit Facility, whereby all terms and covenants of the $240 million Revolver apply to the new combined facility. This consolidation feature was specifically structured as part of the $240 million Revolver at its inception. Second, this new $340 million Revolving Credit Facility ("Revolving Credit Facility") was again amended in October 2005, with respect to pricing, to reflect Western's improved financial profile. The amendments reduced the pricing to nil to 225 basis points over the bank prime lending rate, bankers acceptances or US LIBOR notes, as applicable, which formerly ranged from 100 to 200 basis points. At December 31, 2005, $41 million (2004 – $216 million) had been drawn on this facility, with $258 million in unused capacity. Additionally, as at December 31, 2005, letters of credit issued in the amount of $8.9 million (2004 – $8.1 million) were outstanding under the Revolving Credit Facility.

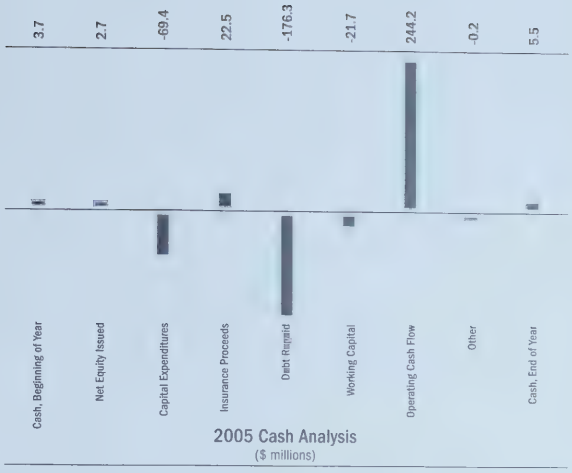
The size of the Revolving Credit Facility is a function of the value of the reserves attributable to Western. Therefore, based on the reserve evaluation as at December 31, 2005, Western has full access to the $340 million limit under the Revolving Credit Facility. As Western and its Joint Venture Participants commit to expansions and the associated reserves are attributed proratably to each partner, Western may have the ability to increase its debt capacity beyond the current limits.

Equity Capital

At December 31

	2005
Issued and Outstanding:	
Common Shares	160,518,041
Outstanding:	
Stock Options	3,527,932
Fully Diluted Number of Shares	164,045,973





Equity Financing

Cash flow from operations was more than sufficient to fund the modest capital expenditures and working capital commitments during 2005. We will continue to assess all forms of financing vehicles, both in the debt and equity capital markets, to ensure Western's capital structure is highly efficient in any given circumstance.

The share performance graph compares the yearly change in the cumulative total shareholder return of a $100 investment made on December 31, 2000 in the Company's Common Shares with the cumulative total return of the S&P/TSX Total Return Composite Index and the S&P/TSX Capped Energy Index, assuming the reinvestment of dividends, where applicable, for the comparable period. Western has significantly outperformed both indices since the Company's inception.

Capital Expenditures

Capital expenditure programs are conducted under the Joint Venture Agreement whereby we participate in the operations of the Project to our 20 per cent working interest, and we are responsible for our respective share of the costs. Western also incurs capital expenditures of its own accord as a result of new business development initiatives. Net capital expenditures totalled $46.8 million in 2005 compared to $40.0 million in 2004. The majority of the gross increase in capital expenditures relates primarily to increased business development activity which rose to $13.3 million in 2005 compared to $3.8 million in 2004.

Analysis of Cash Resources

Cash balances totalled $5.6 million at the end of 2005, slightly higher than the $3.7 million at December 31, 2004. Cash inflows included net operating cash flow of $244.2 million, insurance proceeds of $22.5 million and equity proceeds of $2.7 million from the exercise of stock options. Cash outflows included repayments of long-term debt and obligations under capital leases of $176.3 million, capital expenditures of $69.4 million, a working capital decrease of $21.7 million and an increase in deferred charges of $0.2 million.

Record cash flow was generated in 2005 and cash flow in excess of capital expenditures was applied to reduce outstanding bank facilities. Western's strategy is to continue to apply excess cash flow to bank facilities to the extent of outstanding balances. In 2006, our capital expenditure program is projected to increase to $250 million, representing a combination of current base

Capital Expenditures

December 31 ($ millions)	*2005*	*2004*
Project-Related Capital		
Profitability Capital	**31.2**	16.1
Growth Initiatives	**9.0**	7.1
Long-lead Items	**5.6**	–
Sustaining Capital	**5.8**	15.8
Total Project-Related Capital	**51.6**	39.0
Business Development and General Corporate Expenditures	**13.3**	3.8
Capitalized Insurance Costs	**4.4**	3.6
Insurance Proceeds	**(22.5)**	(6.4)
Net Capital Expenditures	**46.8**	40.0

Project capital, capital associated with the first AOSP expansion, as well as capital allocated to identifying new business opportunities where we can utilize our expertise to deliver further shareholder value. To the extent possible, we will strive to maintain a minimal cash balance.

Contractual Obligations and Commitments

Western has assumed various contractual obligations and commitments in the normal course of our operations. Summarized below are significant financial obligations that are known as of February 16, 2006, and represent future cash payments that are required under existing contractual agreements. We have entered into these agreements either directly or as a partner in the Joint Venture. Feedstocks are included in the table below to comply with continuous disclosure obligations in Canada; however, Western could sell these products back to the market and eliminate any negative impact in the event of operational curtailments.

Insurance Claims

At the beginning of the year, Western had two large claims outstanding: at the Joint Venture level, a $500 million ($100 million net to Western) loss of profits claim stemming from the fire at the Mine on January 6, 2003, commonly referred to as Section III, and a stand-alone Western claim of $200 million pursuant to our Cost Overrun and Project Delay Policy commonly referred to as Section IV. In the second quarter of 2005, the Joint Venture was successful in settlement proceedings with the named insurers on Section III in the amount of $220 million ($44 million net to Western). To date, Western, has received $19.4 million of its share of this settlement amount as certain insurers on Section III are also named insurers on Section IV, which have withheld insurance proceeds payable to Western. We hope to receive the outstanding amounts upon conclusion of Section IV arbitration proceedings. Costs and premiums associated with Section III were capitalized as Western was pre-commercial operations at that time and, as such, amounts

Contractual Obligations and Commitments *(1)*

	Payments Due by Period				
($)	*<1 Year*	*1 – 3 Years*	*4 – 5 Years*	*After 5 Years*	*Total*
US$450 Million Senior Secured Notes	–	–	–	524,655	524,655
Revolving Credit Facility *(2)*	–	–	–	41,000	41,000
Obligations under Capital Lease	1,340	2,680	2,680	43,566	50,266
Option Premium Liability	–	95,642	–	–	95,642
Feedstocks	106,423	128,758	18,242	64,138	317,561
Pipelines and Utilities	39,715	68,337	69,890	556,036	733,978
Mobile Equipment Lease	3,647	11,941	26,740	–	42,328
Total Contractual Obligations	151,125	307,358	117,552	1,229,395	1,805,430

(1) In addition, we have an obligation to fund Western's share of the Project's Pension Fund and have made commitments related to our risk management program: see Notes 17 and 18, respectively, of the Consolidated Financial Statements.

(2) The Revolving Credit Facility is a three-year bank facility maturing initially on October 31, 2008, extendible annually at the lenders' discretion. Management considers this to be part of our long-term capital structure.

received pursuant to this settlement were reported as a reduction in capital assets.

Arbitration proceedings under the terms of Section IV of Western's cost overrun and Project delay insurance policy have been initiated to resolve the disputes with insurers surrounding the claims for payment pursuant to this policy. In order to preserve Western's rights regarding this policy, Western has filed insurance claims for the full limit of the policy, namely $200 million, and we will also be seeking interest and punitive and aggravated damages. A number of procedural motions have been heard to date and further motions are expected to occur prior to the commencement of the main arbitration hearing. Some of the decisions relating to the preliminary motions have been appealed in the past and one is currently in appeal, resulting in delays to the commencement of the main arbitration hearing, which is now expected to occur in 2007. We continue to work toward a satisfactory conclusion to these proceedings.

Similar to Section III, there are also amounts being withheld by certain insurers relating to the January 6, 2003 physical property damage claim, commonly referred to as Section I. To date, Western has received $16.1 million on this claim, with $19.4 million outstanding. The principal amount of Western's outstanding insurance claims is $244 million. Other than amounts collected up to December 31, 2005, no outstanding amounts are recorded in our financial statements nor are they included in any of our financing strategies.

Flow-Through Shares

In connection with the issuance of flow-through shares in 2001 and 2002, Western renounced Canadian exploration expenses in the aggregate amount of $29.2 million and $19.5 million, respectively. Under the mechanics of renouncing qualifying expenditures pursuant to flow-through shares, individual shareholders can reduce their income subject to personal income taxes. Commencing in the latter part of the year, discussions were held between the AOSP and the CRA regarding the proper characterization of certain expenditures included in the Canadian exploration expenses in those years. If the CRA successfully asserts a change in the characterization of these expenditures, any resulting reduction in the renunciations could impact Western's obligations under the indemnity provisions in the subscription agreements and in turn, will impact Western's reported results. The subscription agreements for such flow-through shares stipulate that Western has indemnified subscribers for an amount equal to the tax payable and any associated interest by the subscribers if such renunciations are reduced under the *Income Tax Act* (Canada).

Fourth Quarter 2005

Western achieved a third consecutive quarter of record production in the fourth quarter of 2005, averaging 35,572 barrels per day. Earnings and cash flow for the fourth quarter were robust when compared to previous quarters. Record fourth quarter production, however, did not translate into corresponding record earnings or cash flow due to several factors. First, similar to the fourth quarter of 2004, the heavy oil differential to WTI increased in the last quarter of the year to approximately 42 per cent. This adversely impacted overall sales price realizations as a portion of our sales stream received a larger discount compared to the prior quarter, where the average differential to WTI was approximately 32 per cent. Second, the average WTI price for the fourth quarter was $60.02 per barrel compared to $63.19 per barrel for the third quarter of 2005. As underlying crude oil prices decline, our cash flow and profitability decrease accordingly, as our operations are sensitive to fluctuations in crude oil prices. Third, the continued strength in the US/Cdn exchange rate adversely impacted financial results. The average exchange rate for the fourth quarter was US/Cdn$0.8524 compared to US/Cdn$0.8325 for the third quarter of 2005. To the extent this exchange rate strengthens, Western receives fewer Canadian dollars on its US dollar sales. Due to these factors, our sales price realizations totalled $50.65

per barrel in the fourth quarter compared to $58.79 per barrel for the third quarter. As far as operating costs are concerned, natural gas prices increased 57 per cent in the fourth quarter despite the decline in WTI prices. NYMEX closing settlement prices averaged US$12.91/Mcf for the fourth quarter compared to US$8.21/Mcf for the third quarter, resulting in relatively higher operating costs than what would normally be expected in a decreasing WTI environment.

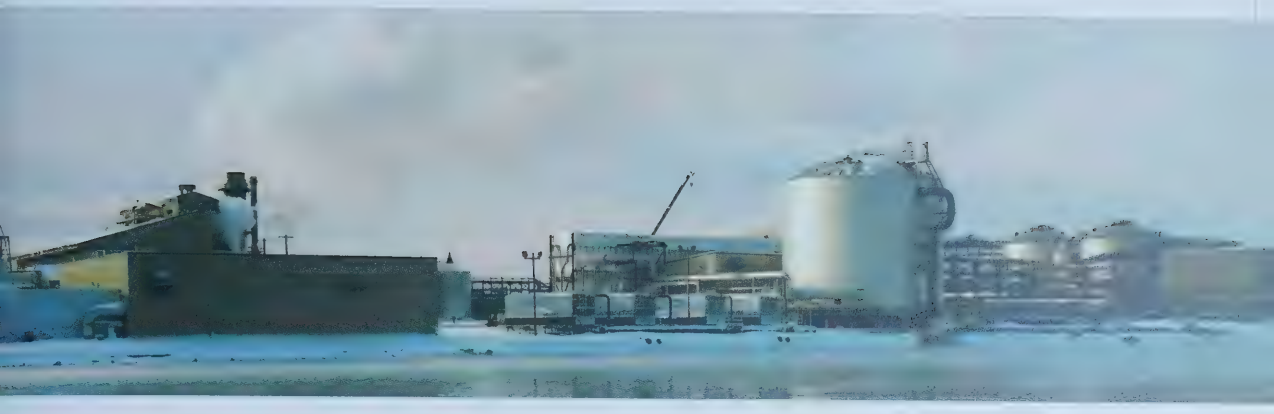
OUTLOOK FOR 2006

We caution readers and prospective investors of the Company's securities to not place undue reliance on forward-looking information as by its nature, it is based on current expectations regarding future events that involve a number of assumptions, inherent risks and uncertainties, which could cause actual results to differ materially from those anticipated by Western. These risks include, but are not limited to, risks of commodity prices in the marketplace for crude oil and natural gas; risks associated with the extraction, treatment and upgrading of mineable oil sands deposits; risks surrounding the level and timing of capital expenditures required to fulfill the Project's growth strategy; risks of financing these growth initiatives at commercially attractive levels; risks of being unable to participate in expansion and corresponding loss of voting rights in the AOSP; risks relating to the execution of the Project's optimization strategy; risks involving the uncertainty of estimates involved in the reserve and resource estimation process and ore body configuration/geometry, uncertainty in the assessment of asset retirement obligations, uncertainty in the estimation of future income taxes, and uncertainty in treatment of capital for royalty purposes; risks surrounding health, safety and environmental matters; risk of foreign exchange rate fluctuations; risks and uncertainties associated with securing the necessary regulatory approvals for expansion initiatives; risks surrounding major interruptions in operational performance together with any associated insurance proceedings thereto; and risks associated with identifying, negotiating and completing our other business development activities, both those that relate to oil sands activities and those that do not, either domestically or abroad.

In 2006, we look forward to achieving continued operational improvements as we continue to seek ways to optimize performance at the AOSP. First quarter results will be impacted by unplanned production interruptions resulting from a tear in the main conveyor belt at the Mine that transports bitumen ore from the primary crushers to the extraction plant. Operations resumed full production design rates in late March on completion of the belt replacement. 2006 operations will also be impacted by the first full planned turnaround of the entire Project during the second quarter of this year. Much care and planning has been directed to this effort to ensure an expeditious return to full production in mid-2006. Western continues to maintain production guidance of 145,000 to 150,000 barrels per day (29,000 to 30,000 barrels per day, net to Western).

Western's capital expenditure program for 2006 is estimated at approximately $250 million, which is comprised of $71 million for AOSP base Project improvement capital, $137 million for AOSP growth expenditures and $42 million for Western-led corporate development initiatives. Of this latter amount, the majority of the budgeted capital relates to oil sands related initiatives and downstream opportunities.

Western does not have any physical barrels subject to hedging contracts for fiscal 2006 and is well-placed to take full advantage of the continued strength in commodity prices during the year should this occur. Financial results for 2006 are expected to be more highly correlated to underlying movements in crude oil prices due to the absence of financial risk management instruments. In addition, we will continue to monitor our 2007 to 2009 risk management positions.



In 2005, Shell acquired other mineable leases in the Athabasca region and Western has an option to earn a working interest in these additional leases upon satisfying certain provisions of the Joint Venture Agreement. Taking into account these additional leases, together with the right to participate in the Chevron heavy oil leases along with Western's operated in-situ lease, translates into a land position, net to Western, which has more than doubled over the past year. An extensive core-hole drilling program is planned to evaluate these new leases over the next several years, in addition to previously held leases, to determine the resource potential available for future development.

The AOSP is our core asset and primary focus. The expansion plans that are underway will bring Western's production from the Project to 100,000 to 120,000 barrels per day over the next eight to ten years. In addition, Western's long-term growth strategy includes maintaining under evaluation four to six potentially significant project opportunities, each of which is designed to create long-term shareholder value. These projects include research and development efforts to add value to our existing assets, downstream initiatives to reduce our exposure to heavy oil differentials, and identifying and evaluating opportunities in resource development of oil sands and other ventures with significant long-life hydrocarbon resource potential.

RISK AND SUCCESS FACTORS RELATING TO WESTERN

Western faces a number of risks that we need to manage in conducting our business affairs. The following discussion identifies some of our key areas of exposure and, where applicable, sets forth measures undertaken to reduce or mitigate these exposures. A complete discussion of risk factors that may impact our business is provided in our Annual Information Form.

Financial Risks

The table below details the sensitivities of our cash flow and net earnings per share to certain relevant operating factors of the Project for 2006.

Our financial results will depend on, amongst other factors, the prevailing price of crude oil and the Canadian/US currency exchange rate. Oil prices and currency exchange rates fluctuate

Sensitivity Analysis

Variable	*Sensitivity Case*	*Variation*	*Basic Cash Flow ($ millions)*	*Cash Flow per Share ($)*	*Basic Earnings ($ millions)*	*Basic Earnings per Share ($)*
Production	30,000	1,000 bbls/day	19.49	0.12	11.90	0.07
Oil Price *(US$WTI/bbl)*	56.00	US$1.00/bbl	10.25	0.06	6.87	0.04
Non-Gas Operating Costs	21.75	$1.00/bbl	10.97	0.07	7.36	0.05
Natural Gas Price *(Cdn$/mcf)* (1)	10.02	$0.10/Mcf	0.60	0.00	0.40	0.00
Foreign Exchange (2)	0.86	US/Cdn 0.01	5.93	0.04	0.12	0.04

(1) Each $1.00 per thousand cubic feet change in gas price results in a change of $0.44 per barrel in operating costs.

(2) Excludes unrealized foreign exchange gains or losses on long-term monetary items. The impact of the Canadian dollar strengthening by US$0.01 would increase net earnings by $2.7 million, based on December 31, 2004 US dollar denominated debt levels.

significantly in response to supply and demand factors beyond our control and could have an impact on future financial results. Any prolonged period of low oil prices could result in a decision by the Joint Venture Owners to suspend or reduce production. Any such suspension or reduction of production would result in a corresponding decrease in our future revenues and earnings and could expose Western to significant additional expense as a result of certain long-term contracts. In addition, because natural gas comprises a substantial part of variable operating costs, any prolonged period of high natural gas prices could negatively impact our future financial results.

Our debt level and restrictive covenants will have an important impact on our future operations. Our ability to make scheduled payments or to refinance our debt obligations will depend upon our financial and operating performance, which, in turn, will depend on prevailing industry and general economic conditions beyond our control. There can be no assurance that our operating performance, cash flow and capital resources will be sufficient to repay our debt and other obligations in the future.

To mitigate our exposure to these financial risks and provide a stable financial footing as we enter the first phase of the AOSP expansion, we recently completed a strategic crude oil risk management program. This program was the culmination of extensive internal analysis and review and the recommended approach was approved by our Board of Directors. The overriding objective of the risk management program was to ensure the ability to fund significant capital expenditures in the event of a precipitous drop in the crude oil price. The program itself was a series of put and call options. Western purchased puts at various levels and financed in part the cost of these puts by selling call options on lower volumes over the same time period. The net cost of the program was US$3.74 per put barrel. All options bought and sold were executed on a deferred basis. Hence, Western made no upfront cash payment for these options but will do so as each monthly option expires. Western deferred the options in order to properly match the underlying cash flow, but, more importantly, the implicit interest rate within the deferred options pricing was lower than Western's incremental borrowing

Risk Management Activities

	Period (calendar year)		
	2007	*2008*	*2009*
Put Options Purchased *(bbls/d)*	20,000	20,000	20,000
Call Options Sold *(bbls/d)*	10,000	15,000	15,000
Average Put Strike Price *(US$/bbl)*	52.50	54.25	50.50
Average Call Strike Price *(US$/bbl)*	92.50	94.25	90.50

($ thousands)	***2005***	*2004*
Risk Management Asset – Beginning of Period	–	–
Net Premium	**84,976**	–
Increase in Fair Value	**13,450**	–
Risk Management Asset – End of Period	**98,426**	–

rate. An interest expense associated with this program is a result of this deferral strategy. The program is summarized as follows:

We must finance our share of the Project's operating costs in light of a volatile commodity price environment and ramp-up challenges. Should insufficient cash flow be generated from operations, additional financing may be required to fund capital projects and future expansion projects. If there is a business interruption, we may need additional financing to fund our activities until Business Interruption Insurance proceeds are received.

Operational and Business Risks

We are currently a single asset company. This asset is our investment in oil sands through the AOSP. As such, the vast majority of our capital expenditures are directly or indirectly related to oil sands construction and development, with the majority of our operating cash flow derived from oil sands operations.

We are subject to the operational risks inherent in the oil sands business. Any unplanned operational outage or slowdown can impact production levels, costs and financial results. Factors that could influence the likelihood of this include, but are not limited to, uncertainties within the ore body, extreme weather conditions and mechanical difficulties.

We sell our share of synthetic crude oil production to refineries in North America. These sales compete with the sales of both synthetic and conventional crude oil. Other suppliers of synthetic crude oil exist and there are several additional projects being contemplated. If undertaken and completed, these projects will result in a significant increase in the supply of synthetic crude oil to the market. In addition, not all refineries are able to process or refine synthetic crude oil. There can be no assurance that sufficient market demand will exist at all times to absorb our share of the Project's synthetic crude oil production at economically viable prices.

As an owner in the AOSP, we actively participate in operational risk management programs implemented by the Joint Venture to mitigate the above risks. Our exposure to operational risks is also managed by maintaining appropriate levels of insurance. To that end, in October 2005, we placed US$800 million of Property and Business Interruption Insurance, up from the US$500 million that was placed last year as well as our US$100 million of Liability Insurance to protect our ownership interest against losses or damages to the Owners' facilities, to preserve our operating income and to protect against our risk of loss to third parties.

The Project depends upon successful operation of facilities owned and operated by third parties. The Joint Venture Owners are party to certain agreements with third parties to provide for, among other things, the following services and utilities:

- Pipeline transportation is provided through the Corridor Pipeline;
- Electricity and steam are provided to the Mine and the Extraction Plant from the Muskeg River cogeneration facility;
- Transportation of natural gas to the Muskeg River cogeneration facility is provided by the ATCO pipeline;
- Hydrogen is provided to the Upgrader from the hydrogen manufacturing unit ("HMU") and Dow Chemicals Canada Inc. ("Dow"); and
- Electricity and steam are provided to the Upgrader from the Upgrader cogeneration facility.

All of these third-party arrangements are critical to the successful operation of the Project. Disruptions related to these facilities could have an adverse impact on future financial results.

We may be faced with competition from other industry participants in the oil sands business. This could take the form of competition for skilled people, increased demands on the Fort McMurray infrastructure (housing, roads, schools, etc.) or higher prices for the products and services required to operate and maintain the plant. We have significant plans for expansion and the strong working relationship the Project has developed with the trade unions will be an important factor in our future activities. Our relationship with our employees and provincial building trade

unions is important to our future because poor productivity and work disruptions may adversely affect the Project – whether in construction or in operations.

Western has announced its business strategy of investigating, at any one time, several separate projects that could significantly enhance shareholder value. Some of these projects may be located outside of Canada. These potential investments may involve such risks as uncertain political, economic, legal, regulatory and tax environments.

Environmental Risks

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called greenhouse gases ("GHG"). The Project will be a significant producer of some GHGs covered by the treaty. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set GHG emission reduction requirements for various industrial activities, including oil and gas production. Future federal legislation, together with existing provincial emission reduction legislation, such as in *Alberta's Climate Change and Emissions Management Act*, may require the reduction of emissions and/or emissions intensity from the Project. The direct or indirect costs of such legislation may adversely affect the Project. There can be no assurance that future environmental approvals, laws or regulations will not adversely impact the Owners' ability to operate the Project or increase or maintain production or will not increase unit costs of production. Equipment from suppliers that can meet future emission standards or other environmental requirements may not be available on an economic basis, or at all, and other methods of reducing emissions to required levels may significantly increase operating costs or reduce output.

We will be responsible for compliance with terms and conditions set forth in the Project's environmental and regulatory approvals and all laws and regulations regarding the decommissioning and abandonment of the Project and reclamation of its lands. The costs related to these activities may be substantially higher than anticipated. It is not possible to accurately predict these costs since they will be a function of regulatory requirements at the time and the value of the equipment salvaged. In addition, to the extent we do not meet the minimum credit rating required under the Joint Venture agreement, we must establish and fund a reclamation trust fund. We currently do not hold the minimum credit rating. Even if we do hold the minimum credit rating in the future, it may be determined that it is prudent or be required by applicable laws or regulations to establish and fund one or more additional funds to provide for payment of future decommissioning, abandonment and reclamation costs. Even if we conclude that the establishment of such a fund is prudent or required, we may lack the financial resources to do so.

The Joint Venture partners have established programs to monitor and report on environmental performance including reportable incidents, spills and compliance issues. In addition, comprehensive quarterly reports are prepared covering all aspects of health, safety and sustainable development on Lease 13 and the Upgrader to ensure that the Project is in compliance with all laws and regulations and that management is accountable for performance set by the Joint Venture Owners.

NON-GAAP FINANCIAL MEASURES

Western includes cash flow from operations per share, netback per barrel and earnings before interest, taxes, depreciation, depletion and amortization, stock-based compensation, accretion on asset retirement obligation, foreign exchange gains and risk management gains ("EBITDAX") as investors may use this

information to better analyze our operating performance. We also include certain per barrel information, such as realized crude oil sales price and operating costs, to provide per unit numbers that can be compared against industry benchmarks, such as the Edmonton PAR benchmark. The additional information should not be considered in isolation or as a substitute for measures of operating performance prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). Non-GAAP financial measures do not have any standardized meaning prescribed by Canadian GAAP and are therefore unlikely to be comparable to similar measures presented by other issuers. Management believes that, in addition to Net Earnings (Loss) per Share and Net Earnings (Loss) Attributable to Common Shareholders (both Canadian GAAP measures), Cash Flow from Operations per Share and EBITDAX provide a better basis for evaluating our operating performance, as they both exclude fluctuations on the US dollar denominated Senior Secured Notes, risk management gains (losses) and certain other non-cash items, such as depreciation, depletion and amortization, and future income tax recoveries. In addition, EBITDAX provides a useful indicator of our ability to fund our financing costs and any future capital requirements.

MANAGEMENT CONTROLS AND PROCEDURES

As of December 31, 2005, an evaluation was carried out, under the supervision of and with the participation of management, including the President and Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as defined under Multilateral Instrument 52-109. Based on that evaluation, the President and Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective.

CRITICAL ACCOUNTING ESTIMATES

Western's critical accounting estimates are defined as those estimates that have a significant impact on the portrayal of our financial position and operations and that require management to make judgments, assumptions and estimates in the application of Canadian GAAP. Judgments, assumptions and estimates are based on historical experience and other factors that Management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change. We believe the following are the critical accounting estimates used in the preparation of our Consolidated Financial Statements.

Property, Plant and Equipment ("PP&E")

Western capitalizes costs specifically related to the acquisition, exploration, development and construction of the Project and other initiatives. This includes interest, which is capitalized during the construction and start-up phase for each project. Depletion on crude oil properties is provided over the life of proved and probable reserves on a unit of production basis, commenced when the facilities are substantially complete and after commercial production has begun. Other PP&E assets are depreciated on a straight-line basis over their useful lives, except for lease acquisition costs and certain Mine assets, which are amortized and depreciated over the life of proved and probable reserves. Reserve estimates can have a significant impact on earnings, as they are a key component to the calculation of depletion. A downward revision in the reserve estimate would result in increased depletion and a reduction of earnings.

PP&E assets are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated future cash flows. If an impairment is identified, the assets are written down to the estimated fair

market value. The calculation of these future cash flows is dependent on a number of estimates, which include reserves, timing of production, crude oil price, operating cost estimates and foreign exchange rates. As a result, future cash flows are subject to significant management judgment.

Asset Retirement Obligation

Western recognizes an asset and a liability for asset retirement obligations in the period in which they are incurred by estimating the fair value of the obligation. We determine the fair value by first estimating the expected timing and amount of cash flow, using third-party costs that will be required for future dismantlement and site restoration, and then calculating the present value of these future expenditures using a credit-adjusted risk-free rate appropriate for Western. Any change in timing or amount of the cash flow subsequent to initial recognition results in a change in the asset and liability, which then impacts the depletion on the asset and the accretion charged on the liability. Estimating the timing and amount of third-party cash flow to settle this obligation is inherently difficult and is based on Management's current experience.

Derivative Financial Instruments

Financial instruments that do not qualify as hedges, or have not been designated as hedges under Accounting Guideline 13, are recorded using the mark-to-market method of accounting whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or a liability with changes in fair value recognized in net earnings. The fair values of such financial instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity. Financial instruments that do qualify as hedges under Accounting Guideline 13, and are designated as hedges, are not recognized on the Consolidated Balance Sheet and gains and losses on the hedge are deferred and recognized in revenues in the period the hedge sale transaction occurs.

Income Tax

Western follows the liability method of accounting for income taxes whereby future income taxes are recognized based on the differences between the carrying values of assets and liabilities reported in the Consolidated Financial Statements and their respective tax basis. Future income tax assets and liabilities are recognized at the tax rates at which Management expects the temporary differences to reverse. Management bases this expectation on future earnings, which require estimates for reserves, timing of production, crude oil price, operating cost estimates and foreign exchange rates. As a result, future earnings are subject to significant Management judgment and changes.

Arrangements Containing a Lease

Through its 20 per cent ownership interest in AOSP, Western is party to a number of long-term third-party arrangements to provide for pipeline transportation of bitumen and upgraded products, and to provide electrical and thermal energy. With the issuance of the Emerging Issues Committee Abstract 150 ("EIC-150") the Corporation is required to determine whether any arrangements agreed to, committed to or modified after January 1, 2005 contain a lease that is within the scope of CICA Section 3065 "Leases". To date, none of these long-term third-party contracts were agreed to, committed to or modified after January 1, 2005 and therefore, the Corporation is not required to consider whether they contain a lease that is within the scope of CICA Section 3065. However, the AOSP or Western may request modification of these agreements in the future to meet certain requirements related to the AOSP growth plans. Any modifications may result in certain of these long-term third-party arrangements being treated as capital leases, thereby increasing both Western's assets and liabilities on our Consolidated Balance Sheet.

WESTERN OIL SANDS FINANCIAL INFORMATION

For the year ended December 31, 2006

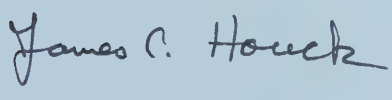
MANAGEMENT'S REPORT

The accompanying Consolidated Financial Statements and all information in the annual report including the Management's Discussion and Analysis are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in accordance with the accounting policies described in the notes to the Consolidated Financial Statements. In the opinion of Management, the Consolidated Financial Statements have been prepared within acceptable limits of materiality and are in accordance with Canadian Generally Accepted Accounting Principles appropriate in the circumstances. The financial information contained elsewhere in the annual report has been reviewed to ensure consistency with that in the Consolidated Financial Statements.

Management has developed and maintains systems of internal controls, policies and procedures in order to provide reasonable assurance as to the reliability of the financial records and the safeguard of assets.

PricewaterhouseCoopers LLP, independent external auditors appointed by the shareholders of the Company, review Western's system of internal controls and conduct their work to the extent they deem appropriate. They have examined the Consolidated Financial Statements and have expressed an opinion on the statements. Their report is included with the Consolidated Financial Statements. Western also retains independent petroleum engineering consultants, GLJ Petroleum Consultants Ltd., to conduct independent evaluations or audits of the Company's oil and gas reserves.

The Board of Directors of the Company has established an Audit Committee consisting of three non-management directors. The Audit Committee reviews with Management and the external auditors any significant financial reporting issues, the presentation and impact of significant risks and uncertainties, and key estimates and judgments of Management that may be material for financial reporting purposes. On an annual basis, the Audit Committee meets with the independent petroleum consultants and reviews the Company's annual reserve estimates. The Audit Committee meets quarterly to review and approve interim financial statements prior to their release, as well as annually to review Western's annual financial statements, Management's Discussion and Analysis and Annual Information Form/Form 40-F, and recommend their approval to the Board of Directors. The external auditors have unrestricted access to the Company, the Audit Committee and the Board of Directors.



James C. Houck
President and Chief Executive Officer
March 28, 2006

David A. Dyck
Senior Vice President, Finance and Chief Financial Officer

TO THE SHAREHOLDERS OF WESTERN OIL SANDS INC.

We have audited the consolidated balance sheets of Western Oil Sands Inc. as at December 31, 2005 and 2004 and the consolidated statements of operations and retained earnings, and cash flows for the years then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian Generally Accepted Auditing Standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Western Oil Sands Inc. as at December 31, 2005 and 2004, and the results of its operations and its cash flows for the years then ended in accordance with Canadian Generally Accepted Accounting Principles.

PricewaterhouseCoopers LLP

Chartered Accountants
Calgary, Canada
February 16, 2006

CONSOLIDATED BALANCE SHEETS

December 31 ($ thousands)	**2005**	*2004*
Assets		
Current Assets		
Cash	**5,590**	3,715
Accounts Receivable	**87,398**	62,564
Inventory (note 4)	**21,083**	14,186
Prepaid Expense	**9,355**	5,771
	123,426	86,236
Property, Plant and Equipment (note 5)	**1,352,605**	1,351,745
Risk Management (note 18)	**98,426**	–
Deferred Charges (note 6)	**16,063**	18,378
Future Income Taxes (note 12)	**–**	14,511
	1,467,094	1,384,634
	1,590,520	1,470,870
Liabilities		
Current Liabilities		
Accounts Payable and Accrued Liabilities	**101,303**	87,679
Current Portion of Long-term Debt (note 7)	**–**	95,000
Current Portion of Lease Obligations (note 8)	**3,396**	5,230
	104,699	187,909
Long-term Liabilities		
Long-term Debt (note 7)	**565,655**	662,620
Lease Obligations (note 8)	**55,809**	53,474
Option Premium Liability (note 9)	**85,416**	–
Asset Retirement Obligation (note 10)	**9,094**	8,191
Future Income Taxes (note 12)	**56,445**	–
	772,419	724,285
	877,118	912,194
Shareholders' Equity		
Share Capital (note 13)	**548,747**	545,699
Contributed Surplus (note 14)	**3,474**	1,245
Retained Earnings	**161,181**	11,732
	713,402	558,676
	1,590,520	1,470,870

Commitments and Contingencies (note 19)

See accompanying notes to the Consolidated Financial Statements

Approved by the Board of Directors

Robert G. Puchniak
Director

Mac H. Van Wielingen
Director

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS (DEFICIT)

Year ended December 31 ($ thousands, except amounts per share)	*2005*	*2004*
Revenues (note 18)	**910,330**	636,911
Less: Purchased Feedstocks and Transportation	**(318,934)**	(315,926)
	591,396	320,985
Expenses		
Operating	**250,389**	212,993
Research and Business Development	**10,657**	4,733
Royalties	**4,005**	2,954
General and Administrative	**11,342**	8,101
Insurance	**7,995**	9,350
Interest (note 11)	**58,165**	61,154
Stock-based Compensation (note 15)	**3,149**	967
Accretion on Asset Retirement Obligation (note 10)	**562**	471
Depreciation, Depletion and Amortization	**50,738**	44,515
	397,002	345,238
Net Earnings (Loss) Before Other Income and Income Taxes	**194,394**	(24,253)
Other Income		
Foreign Exchange Gain	**15,561**	38,350
Risk Management Gain (note 18)	**13,450**	–
Net Earnings Before Income Tax	**223,405**	14,097
Income Tax Expense (Recovery) (note 12)	**73,956**	(5,355)
Net Earnings	**149,449**	19,452
Retained Earnings (Deficit) at Beginning of Year	**11,732**	(7,720)
Retained Earnings at End of Year	**161,181**	11,732
Net Earnings Per Share (note 13)		
Basic	**0.93**	0.12
Diluted	**0.92**	0.12

See accompanying notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 ($ thousands)	*2005*	*2004*
Cash Provided by (Used In)		
Cash from Operating Activities		
Net Earnings	**149,449**	19,452
Non-Cash Items:		
Stock-based Compensation (note 15)	**3,149**	967
Accretion on Asset Retirement Obligations (note 10)	**562**	471
Depreciation, Depletion and Amortization	**50,738**	44,515
Impairment of Long-lived Assets (note 5)	**–**	4,733
Interest Expense on Option Premium Liability (note 9)	**1,278**	–
Unrealized Gain on Risk Management (note 18)	**(13,450)**	–
Unrealized Foreign Exchange Gain (note 7 and note 9)	**(17,803)**	(39,960)
Future Income Tax Expense (Recovery) (note 12)	**70,956**	(7,104)
Cash Items:		
Cash Settlement of Asset Retirement Obligation (note 10)	**(52)**	(30)
Cash Settlement of Performance Share Unit Plan (note 14)	**(596)**	–
Cash Flow from Operations	**244,231**	23,044
(Increase) Decrease in Non-Cash Working Capital (note 20)	**(32,489)**	16,393
	211,742	39,437
Cash from (Used in) Financing Activities		
Issue of Share Capital (note 13)	**2,724**	70,866
Share Issue Expenses (note 13)	**–**	(2,934)
Repayment of Long-term Debt, Net	**(175,000)**	(63,000)
Deferred Charges	**(216)**	(56)
Repayment of Obligations Under Capital Lease	**(1,340)**	(1,343)
	(173,832)	3,533
Cash Invested		
Capital Expenditures	**(69,350)**	(46,399)
Insurance Proceeds (note 19)	**22,517**	6,431
Decrease (Increase) in Non-Cash Working Capital (note 20)	**10,798**	(3,057)
	(36,035)	(43,025)
Increase (Decrease) in Cash	**1,875**	(55)
Cash at Beginning of Year	**3,715**	3,770
Cash at End of Year	**5,590**	3,715

See accompanying notes to the Consolidated Financial Statements

(Tabular amounts in $ thousands, except for share amounts)

1. BUSINESS OF THE CORPORATION

Western Oil Sands Inc. (the "Corporation") was incorporated on June 18, 1999 under the laws of the Province of Alberta. The Corporation holds an undivided 20 per cent working interest in an oil sands project in the Athabasca region of northeast Alberta (the "Athabasca Oil Sands Project" or "AOSP"). Shell Canada Limited and Chevron Canada Limited hold the remaining 60 per cent and 20 per cent interests, respectively. The AOSP consists of direct or indirect participation in the design, construction and operation of mining, extracting, transporting and upgrading of oil sands deposits. The Corporation is pursuing other oil activities related to technology development, downstream initiatives and large, long-life resource capture.

2. SUMMARY OF ACCOUNTING POLICIES

a) Principles of Consolidation

The Consolidated Financial Statements include the accounts of the Corporation and its wholly-owned subsidiary corporations and limited partnership. The Corporation's oil sands activities are conducted jointly with others. These financial statements reflect only the Corporation's proportionate interest in such activities.

b) Measurement Uncertainty

The preparation of the Consolidated Financial Statements in conformity with Canadian Generally Accepted Accounting Principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported amounts of revenues and expenses during the reporting period. Such estimates relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. Accordingly, actual results may differ from these estimated amounts as future confirming events occur. Significant estimates used in the preparation of the Consolidated Financial Statements include, but are not limited to, the estimates of crude oil reserves, asset retirement obligations, income taxes and employee future benefits.

c) Foreign Currency Translation

Accounts in foreign currencies and operations in foreign countries that are integrated are translated into Canadian dollars using the temporal method. Under this method, monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at rates of exchange in effect at the end of the period. Non-monetary assets and liabilities are translated into Canadian dollars at exchange rates prevailing at the transaction dates. Revenues and expenses are translated into Canadian dollars at the monthly average exchange rates. Provisions for depreciation, depletion and amortization are translated at the same rate as the related items. The resulting exchange gains or losses are included in the Consolidated Statements of Operations and Retained Earnings.

d) Cash

Cash presented in the Consolidated Financial Statements is comprised of cash and cash equivalents and includes short-term investments with a maturity of three months or less when purchased.

e) Inventory

Product and Parts, Supplies and Other inventories are stated at the lower of average cost and net realizable value.

f) Property, Plant and Equipment

Property, plant and equipment ("PP&E") assets are recorded at cost less accumulated provisions for depreciation, depletion and amortization. Capitalized costs include costs specifically related to the acquisition, exploration, development and construction of the AOSP and other projects. Prior to the commencement of commercial operations, interest costs on debt attributable to major development projects are capitalized. PP&E assets are reviewed for impairment whenever events or conditions indicate that their net carrying amount may not be recoverable from estimated future cash flows. If an impairment is determined, the assets are written down to the fair market value.

Depletion on crude oil properties is provided over the life of proved and probable reserves on a unit of production basis, commencing when the facilities are substantially complete and after commercial production has begun. Other PP&E assets are depreciated on a straight-line basis over their useful lives, except for lease acquisition costs and certain mine assets, which are amortized and depreciated over the life of proved and probable reserves.

g) Derivative Financial Instruments

The Corporation utilizes financial instruments to manage its exposure to fluctuations in foreign currency exchange rates and commodity prices. These derivative financial instruments are not used for speculative purposes. The Corporation has policies and procedures in place with respect to the required documentation and approvals for the use of financial instruments and specifically ties their use, in the case of commodities, to the mitigation of market price risk associated with cash flows expected to be generated. Where applicable, the Corporation identifies relationships between financial instruments and anticipated transactions, as well as its risk management objectives and the strategy for undertaking the economic hedge transaction. The Corporation assesses, both at inception and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

The fair values of these financial instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity. The Corporation considers all of these financial instruments to be effective economic hedges. However, certain of the Corporation's financial instruments do not qualify or have not been designated as hedges for accounting purposes in accordance with Accounting Guideline 13.

In accordance with Emerging Issues Committee Abstract 128 ("EIC-128") "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments", financial instruments that do not qualify as hedges or have not been designated as hedges are recorded using the mark-to-market method of accounting, whereby instruments are recorded in the Consolidated Balance Sheet as either an asset or a liability with changes in fair value recognized in net earnings. Financial instruments that do qualify as hedges under Accounting Guideline 13 and are designated as hedges are not recognized on the Consolidated Balance Sheet and gains and losses on the hedge are deferred and recognized in revenues in the period the hedge sale transaction occurs.

h) Asset Retirement Obligation

The Corporation recognizes an asset and a liability for asset retirement obligations in the period in which they are incurred by estimating the fair value of the obligation. The fair value is determined by the Corporation by first estimating the expected timing and amount of cash flows, using third-party costs, that will be required for future dismantlement and site restoration, and then calculating the present value of these future expenditures using a credit-adjusted risk-free rate appropriate for the Corporation. Any change in timing or amount of the cash flows subsequent to initial recognition results in a change in the asset and liability. The Corporation recognizes, over the estimated life of the asset and liability, depletion on the asset and accretion on the liability. Actual expenditures incurred are charged against the accumulated obligation.

i) Stock-based Compensation Plans

The Corporation has a stock-based compensation plan, which is described in note 15(a). Effective January 1, 2002, the Corporation adopted CICA Section 3870, "Stock-based Compensation and Other Stock-based Payments". This Section is applied to all stock-based payments to non-employees and to employee awards that are direct awards of stock, stock appreciation rights and similar awards to be settled in cash. This Section is applied to all grants of stock options on or after January 1, 2002.

During the fourth quarter of 2003, effective for January 1, 2003, the Corporation began prospectively recognizing compensation expense for options granted under the plan in accordance with the fair value method. Under the transitional provisions in this Section, the Corporation is required only to apply the fair value based method and record compensation expense and Contributed Surplus to awards granted, modified or settled on or after the beginning of the fiscal year in which the Corporation adopts the fair value method for those awards. Accordingly, only awards issued on or after January 1, 2003 require compensation expense to be recognized in accordance with this Section. Compensation expense for options granted subsequent to 2003 is determined based on the fair values at the time of grant and is recognized over the estimated vesting periods of the respective options. For options granted prior to January 1, 2003, the Corporation continues to disclose the pro forma net earnings impact of the related compensation expense. Pro forma compensation-related earnings impacts are determined on the same basis as the 2003 options.

Consideration received on the exercise of stock options granted is credited to share capital, and if related to any stock options that were granted subsequent to December 31, 2002, then an amount equal to the compensation expense recognized to that date is reclassified from Contributed Surplus to Common Shares.

The Corporation has a Performance Share Unit Plan ("PSUP") which is described in note 15(b). The Corporation recognizes compensation expense, and contributed surplus, related to this plan in accordance with the fair value method.

The Corporation has a Deferred Share Unit Plan ("DSUP") which is described in note 15(c). The Corporation recognizes compensation expense and a liability relating to this plan in accordance with the fair value method.

The Corporation, as an owner in the AOSP, shares in any related costs associated with the AOSP's stock-based compensation plans. The AOSP's plans involve Stock Appreciation Rights ("SARs") which are described in note 15(e) which may require settlement with cash payments. During the vesting period, compensation expense is recognized using the graded vesting approach when the value of the SARs exceeds the award value. The Corporation's share of the change in value of the SARs is recognized in operating expense in the year the change occurs.

j) Revenue Recognition

The revenue associated with the sale of crude oil products is recorded when title and other significant risks and rewards of ownership are passed to the customer and delivery has occurred.

k) Income Taxes

The Corporation follows the liability method of accounting for income taxes. Under this method, future income taxes are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the Consolidated Financial Statements and their respective tax bases, using income tax rates substantively enacted on the Consolidated Balance Sheet date. The effect of a change in income tax rates on future income tax assets and liabilities is recognized in earnings in the period the change occurs.

l) Net Earnings Per Share

Basic net earnings per share are calculated by dividing the net earnings available to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted net earnings per share reflect the potential dilution that would occur if stock options or Warrants were exercised. The Corporation uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price for the period.

m) Employee Future Benefits

The Corporation has a defined contribution pension plan for its direct employees and, as a result of the 20 per cent ownership in the AOSP, has a defined benefit pension plan for employees of the AOSP. For the defined contribution pension plan, the expense is recognized as payments are made or entitlements are earned.

For the defined benefit pension plan, the costs are determined using the projected benefit method prorated on length of service and reflects the AOSP's best estimate of expected plan investment performance, salary escalation, retirement ages of employees, withdrawal rates and mortality rates. The expected return on plan assets is based on the fair value of those assets and the obligation is discounted using a market interest rate at the beginning of the year based on high quality corporate debt instruments. Pension expense includes the cost of pension benefits earned during the current year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of adjustments arising from pension plan amendments and the excess of the net actuarial gain or loss over ten per cent of the greater of the benefits obligation and the fair value of plan assets. The amortization period covers the expected average remaining service lifetime of employees covered by the plans.

n) Comparative Amounts

Certain comparative amounts have been reclassified to conform to the current year's presentation.

3. CHANGES IN ACCOUNTING POLICIES

a) Variable Interest Entities

On January 1, 2005, the Corporation adopted Canadian Accounting Guideline 15 (AcG 15), "Consolidation of Variable Interest Entities" ("VIE") without restatement of prior periods. AcG 15 requires consolidation of a VIE where a company will absorb a majority of a VIE's losses, receive a majority of its returns, or both. The Corporation has entered into operating leases, as described in note 19(a), with a VIE. These operating leases, as currently structured, do not meet the AcG 15 criteria for consolidation by the Corporation and therefore, the adoption of this accounting policy had no impact on the Corporation's Consolidated Financial Statements.

b) Arrangements Containing a Lease

On January 1, 2005, the Corporation adopted Emerging Issues Committee Abstract 150 ("EIC-150"). EIC-150 requires the Corporation to determine whether any arrangements agreed to, committed to or modified after January 1, 2005 contain a lease that is within the scope of CICA Section 3065, "Leases". There is no impact on the Consolidated Financial Statements as the Corporation does not have any arrangements agreed to, committed to or modified after January 1, 2005 that contain a lease that is within the scope of CICA Section 3065.

4. INVENTORY

	2005	2004
Product Inventory	**11,262**	8,314
Parts, Supplies and Other	**9,821**	5,872
	21,083	14,186

5. PROPERTY, PLANT AND EQUIPMENT

2005	Cost	Accum. DD&A*	Net
Athabasca Oil Sands Project			
Producing Assets	**1,350,436**	**(105,010)**	**1,245,426**
Capital Leases	**52,705**	**(4,294)**	**48,411**
Expansion	**38,235**	**–**	**38,235**
	1,441,376	**(109,304)**	**1,332,072**
Corporate and Other	**21,895**	**(1,362)**	**20,533**
	1,463,271	**(110,666)**	**1,352,605**

2004	Cost	Accum. DD&A*	Net
Athabasca Oil Sands Project			
Producing Assets	1,341,395	(58,955)	1,282,440
Capital Leases	52,705	(2,439)	50,266
Expansion	11,560	–	11,560
	1,405,660	(61,394)	1,344,266
Corporate and Other	8,545	(1,066)	7,479
	1,414,205	(62,460)	1,351,745

* Accumulated Depreciation, Depletion and Amortization

The Producing Assets in the AOSP net cost includes asset retirement costs of $7.2 million ($7.0 million – 2004). Costs of $38.2 million ($11.6 million – 2004) relating to Major Projects in Progress and $15.5 million ($2.9 million – 2004) relating to Corporate and Other are currently not subject to depreciation, depletion and amortization as these projects were not substantially complete and commercial production has not begun.

During 2004, an asset with an aggregate cost of $4.7 million was written off and included in Research and Business Development expenses after the Corporation determined it to be impaired. The asset related to certain activities the Corporation was pursuing regarding hydrogen production technology. The asset was determined to be impaired after the Corporation received a negative preliminary technical analysis of the technology.

6. DEFERRED CHARGES

	2005	2004
Deferred Charges	**28,712**	28,496
Less: Amortization	**(12,649)**	(10,118)
	16,063	18,378

Deferred charges include primarily debt financing costs that have been incurred in establishing the Corporation's various debt facilities. These amounts are being amortized over the term of the related debt facilities.

7. LONG-TERM DEBT

		2005	2004
US$450 million Senior Secured Notes	(a)	**524,655**	541,620
Senior Credit Facility	(b)	**–**	95,000
Revolving Credit Facility	(c)	**41,000**	121,000
		565,655	757,620
Less: Current Portion of Long-term Debt	(b)	**–**	(95,000)
		565,655	662,620

a) The Senior Secured Notes (the "Notes") bear interest at 8.375 per cent and have a maturity of May 1, 2012. The Notes provide the holders with security over all the assets of the Corporation, subordinated to the $340 million Revolving Credit Facility ("Revolving Credit Facility") described in note 7(c), until the Corporation achieves an investment grade corporate credit rating, at which time the Notes become unsecured.

The Notes are recorded in Canadian dollars at the exchange rate in effect at the balance sheet date. An unrealized foreign exchange gain totalling $17 million was recognized for the year ended December 31, 2005 (December 31, 2004 – $40 million) as a result of changes in the foreign exchange rate between the US and Canadian dollars. As at December 31, 2005, a total of $184.2 million of unrealized foreign exchange gains were recognized since the inception of the Notes, approximately $92 million of which has been capitalized as the unrealized gains occurred prior to commercial operations.

b) The Corporation refinanced the $100 million Senior Credit Facility ("Senior Credit Facility") during the first quarter of 2005 by utilizing a clause that was included in the Revolving Credit Facility described in note 7(c). The clause enabled the Corporation to increase the Revolving Credit Facility by $100 million. The terms of the increase were consistent with those included in the original $240 million Revolving Credit Facility. The Senior Credit Facility, bearing interest at the lenders' prime lending rate, the bankers' acceptance rate or the LIBOR rate plus applicable margins ranging from 100 to 200 basis points was to mature and be repayable on April 23, 2005.

c) The Revolving Credit Facility bears interest at the lenders' prime lending rate, the bankers' acceptance rate or the LIBOR rate plus applicable margins ranging from nil to 225 basis points. The Revolving Credit Facility provides the banks with security over all of the assets of the Corporation, with the exception of certain intercompany notes and note guarantees in connection with the Notes detailed in note 7(a), and have certain financial covenants, including a limit on the amount available for drawdown. At December 31, 2005, the limit available for drawdown was $299 million ($281 million – 2004), of which $41 million ($121 million – 2004) had been drawn and $8.9 million ($8.1 million – 2004) had been issued in letters of credit.

Certain terms of the Revolving Credit Facility were amended during the fourth quarter of 2005. The 364 day revolving feature with a two year term-out for non-revolving allocations was amended to a three year revolving maturity, extendible annually at the lending institutions' discretion. Secondly, the spreads added to the prime lending rate and the banker's acceptance rate or the LIBOR rate were adjusted. Initially, these margins were 100 to 200 basis points and after the amendment, these margins are nil to 225 basis points.

8. LEASE OBLIGATIONS

		2005	2004
Obligations Under Capital Lease	(a)	**50,266**	51,609
Operating Lease Guarantee Obligation	(b)	**8,939**	7,095
		59,205	58,704
Less: Current Portion		**(3,396)**	(5,230)
		55,809	53,474

a) The capital lease obligation relates to the Corporation's share of capital costs for the hydrogen manufacturing unit within the Project. Repayment of the principal obligation was $1.3 million in 2005 and is scheduled to remain at that level until fully repaid.

b) Under the Mobile Equipment Lease, described in note 19(a), the Corporation is committed to pay its 20 per cent share of an amount equal to 85 per cent of the original cost of the equipment to the lessor at the end of the terms of the lease. Accordingly, the Corporation recognizes, as a liability, a portion of this future payment as it relates to the service life of the equipment that has passed. For the year ended December 31, 2005, the Corporation paid $2.3 million (December 31, 2004 – nil) in regards to this obligation.

9. OPTION PREMIUM LIABILITY

The Corporation deferred payment and receipt of the premiums associated with the options described in note 18(a)(ii) until the settlement of the option contracts between 2007 and 2009. The total net premiums payable by the Corporation are US$21.9 million for 2007, US$32.4 million for 2008 and US$27.8 million for 2009. On the dates that the option contracts were entered, a net liability was recognized on the Consolidated Balance Sheet at the estimated present value of the net premiums payable. Subsequent to the inception dates of the option contracts, interest expense is recognized, with a corresponding increase to the liability, at annual rates ranging from 4.25 per cent to 4.50 per cent. For the year ended December 31, 2005, $1.3 million of interest expense was recognized (December 31, 2004 – nil).

The option premium liability is denominated in US dollars and is translated into Canadian dollars at the period end exchange rate. The unrealized foreign exchange gain arising on the option premium liability for the year ended December 31, 2005 was $0.8 million (December 31, 2004 – nil).

The following table reconciles the change in the net option premium liability:

	2005	2004
Option Premium Liability at Beginning of Year	**–**	–
Net Premiums	**84,976**	–
Interest Expense	**1,278**	–
Unrealized Foreign Exchange Gain	**(838)**	–
Option Premium Liability at End of Year	**85,416**	–

10. ASSET RETIREMENT OBLIGATION

The Corporation, in association with its 20 per cent working interest in the AOSP, is also responsible for its share of future dismantlement costs and site restoration costs in the mining, extracting and upgrading activities. The AOSP currently estimates the total undiscounted amount of these costs to be approximately $195.9 million ($192.5 million – 2004), with the majority of that amount to be paid at the end of the current reserves for the AOSP. In determining the fair value of the Asset Retirement Obligation, the estimated cash flows have been discounted using credit-adjusted risk-free rates between 5.93 per cent and 7.0 per cent. The following table presents the reconciliation of the Asset Retirement Obligation from the beginning of each respective period until the end of that period:

	2005	*2004*
Asset Retirement Obligations at Beginning of Year	**8,191**	7,137
Liabilities Incurred	**393**	613
Liabilities Settled	**(52)**	(30)
Accretion on Asset Retirement Obligation	**562**	471
Asset Retirement Obligations at End of Year	**9,094**	8,191

11. INTEREST EXPENSE

	2005	*2004*
Interest on Long-term Debt	**54,325**	59,118
Interest on Obligations Under Capital Lease	**2,562**	2,036
Interest on Option Premium Liability	**1,278**	–
	58,165	61,154

Cash interest paid for the year ended December 31, 2005 was $57.4 million (December 31, 2004 – $61.0 million). Cash interest received for the year ended December 31, 2005 was $0.2 million (December 31, 2004 – $0.1 million).

12. INCOME TAXES

	2005	*2004*
Large Corporations Tax	**3,000**	1,749
Future Income Tax Expense (Recovery)	**70,956**	(7,104)
Income Tax Expense (Recovery)	**73,956**	(5,355)

Cash taxes paid during the year ended December 31, 2005 were $2.5 million (December 31, 2004 – $1.7 million) and related solely to the Large Corporations Tax.

At December 31, the future income tax liability consists of:

	2005	*2004*
Future Income Tax Assets		
Net Losses Carried Forward	**4,707**	61,697
Share Issue Costs	**973**	1,355
Impairment of Long-lived Assets	**796**	796
Future Income Tax Liabilities		
Capital Assets in Excess of Tax Values	**(39,924)**	(34,242)
Unrealized Foreign Exchange Gain	**(15,500)**	(12,648)
Unrealized Gain on Risk Management	**(4,374)**	–
Debt Issue Costs	**(3,123)**	(2,447)
Net Future Income Tax (Liability) Asset	**(56,445)**	14,511

The following table reconciles income taxes calculated at the Canadian statutory rate of 37.62 per cent (2004 – 38.87 per cent) with actual income taxes:

	2005	*2004*
Net Earnings Before Income Taxes	**223,405**	14,097
Income Tax Expense at Statutory Rate	**84,045**	5,480
Effect of Tax Rate Changes and Timing of Use	**(267)**	(4,826)
Non-taxable Portion of Foreign Exchange Gain	**(3,530)**	(8,815)
Non-taxable Portion of Impairment of Long-lived Assets	**–**	1,044
Resource Allowance	**(10,792)**	(5,012)
Provision to Actual	**642**	5,025
Stock-based Compensation	**858**	–
Large Corporations Tax	**3,000**	1,749
Income Tax Expense (Recovery)	**73,956**	(5,355)

At December 31, 2005, the Corporation had approximately $1.4 billion of tax pools available. Included in the tax pools are $14.0 million of non-capital tax loss carry forward balances as estimated at December 31, 2005, with expiry dates ranging from 2007 to 2014.

13. SHARE CAPITAL

a) Authorized

The Corporation is authorized to issue an unlimited number of Class A shares ("Common Shares"), an unlimited number of non-voting Convertible Class B Equity Shares ("Class B Shares"), an unlimited number of non-voting Class C Preferred Shares and an unlimited number of Class D Preferred Shares, issuable in series.

The Common Shares are without nominal or par value. The Class D Preferred Shares, Series A, which have been issued, were converted into Common Shares at the holders' option prior to redemption on a one-for-one basis.

b) Share Split

The Corporation's shareholders approved a subdivision or share split of its issued and outstanding Common Shares on a three-for-one basis at the Corporation's Annual and Special Meeting held on May 11, 2005. All Common Share and per Common Share amounts have been restated to retroactively reflect the share split.

c) Issued and Outstanding

	Number of Shares	*Amount*
Common shares		
Balance at December 31, 2003	149,868,813	464,704
Issued for Cash	6,000,000	68,000
Issued on Exercise of Employee Stock Options	484,800	1,630
Issued on Exercise of Warrants	1,482,672	1,236
Conversion of Class D Preferred Shares	2,000,001	11,963
Share Issue Costs, Net of Tax	–	(1,834)
Balance at December 31, 2004	159,836,286	545,699
Issued on Exercise of Employee Stock Options	681,755	2,724
Exercise of Stock Options Previously Recognized	–	324
Balance at December 31, 2005	160,518,041	548,747
Class D Preferred Shares		
Balance at December 31, 2003	2,000,001	11,963
Conversion of Class D Preferred Shares	(2,000,001)	(11,963)
Balance at December 31, 2004 and 2005	–	–
Total Share Capital	**160,518,041**	**548,747**

d) Issuances

On April 8, 2004, the Corporation completed a public offering for the issuance of 6,000,000 Common Shares (reflecting the three-for-one split on May 30, 2005) for total proceeds of $68.0 million, before consideration of the share issue costs of $2.9 million ($1.8 million net of tax). The offering was underwritten by a syndicate of Canadian underwriters and undertaken through the filing of a short form prospectus. The Common Shares were offered to the public on a bought-deal basis through a syndicate of Canadian underwriters. Proceeds of this offering were used to pay down certain amounts that had been drawn on the bank debt, for general corporate purposes and for expansion opportunities.

e) Warrants

During the year ended December 31, 2004, 1,482,672 (reflecting the three-for-one split on May 30, 2005) Class A Warrants were exercised for total proceeds of $1.2 million.

f) Class D Preferred Shares

During the year ended December 31, 2004, the Class D Preferred Shares were converted into Common Shares at the holders' option prior to redemption on a one-for-one basis. After considering the three-for-one split on May 30, 2005, the total shares issued on the conversion were 2,000,001.

g) Net Earnings Per Share

The following table summarizes the Common Shares used in calculating Net Earnings per Common Share:

	2005	*2004*
Weighted Average Common Shares Outstanding – Basic	**160,169,887**	156,926,514
Effect of Stock Options and Warrants	**2,739,179**	2,829,882
Weighted Average Common Shares Outstanding – Diluted	**162,909,066**	159,756,396

14. CONTRIBUTED SURPLUS

The following table presents the reconciliation of Contributed Surplus for the year ended December 31:

	2005	*2004*
Contributed Surplus Beginning of Period	**1,245**	278
Stock-based Compensation Expense	**3,149**	967
Cash Settlement of Performance Share Unit Plan	**(596)**	–
Exercise of Stock Options Previously Recognized	**(324)**	–
Contributed Surplus End of Period	**3,474**	1,245

15. STOCK-BASED COMPENSATION

The number of Common Share options outstanding reflects the share split of the Corporation's Common Shares as described in note 13(b).

a) Stock Option Plan

The Corporation has established a Stock Option Plan for the issuance of options to purchase Common Shares to directors, officers and employees of the Corporation and its subsidiaries. Options granted under the Stock Option Plan generally vest on an annual basis over four years. The stock options expire five years from each vesting date.

	2005		2004	
	Number of Options	Weighted Average Exercise Price $	Number of Options	Weighted Average Exercise Price $
Outstanding at Beginning of Year	**3,766,938**	**6.51**	4,034,100	5.75
Granted	**443,670**	**20.23**	318,549	11.61
Exercised	**(681,755)**	**4.00**	(484,800)	3.36
Cancelled	**(921)**	**9.07**	(100,911)	7.18
Outstanding at End of Year	**3,527,932**	**8.72**	3,766,938	6.51
Options Exercisable at End of Year	**2,212,647**	**6.24**	2,220,975	5.02

The following table summarizes Stock Options outstanding and exercisable under the Stock Option Plan at December 31, 2005:

	Options Outstanding			Options Exercisable	
Exercise Price	Number of Options	Weighted Average Remaining Life (Years)	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$2.89 – $5.00	813,200	3.3	3.24	813,200	3.24
$5.01 – $10.00	1,982,500	5.6	7.96	1,340,275	7.81
$10.01 – $15.00	288,562	7.4	11.69	59,172	11.88
$15.01 – $20.00	353,670	8.2	18.71	–	–
$20.01 – $27.75	90,000	8.8	26.18	–	–
	3,527,932	5.5	8.72	2,212,647	6.24

The number of Common Shares reserved for issuance under the Stock Option Plan was 6,656,545 at December 31, 2005 (7,338,300 at December 31, 2004).

b) Performance Share Unit Plan

In February 2004, the Corporation initiated a Performance Share Unit Plan ("PSUP"). Awards under PSUP will be in the form of performance share units ("PSU"), with each PSU entitling the holder to receive one Common Share of the Corporation for no additional consideration and subject to certain restrictions. Each PSU award will vest at a rate of one third of the PSUs awarded thereunder annually over a three-year period, conditional on the Corporation achieving an acceptable total shareholder return against a peer group. If total shareholder return at a particular vesting date is in the bottom 25 per cent of the peer group, none of the PSUs otherwise eligible to vest with respect to such PSU will vest. If total shareholder return at a particular vesting date is in the top 25 per cent of the peer group, 150 per cent of the PSUs eligible to vest on such date will vest. If total shareholder return at a particular vesting date is in the middle 50 per cent of the peer group, all of the PSUs eligible to vest on such date will vest.

The following table presents the reconciliation of the number of PSUs for the year ended December 31:

	2005	2004
Outstanding at Beginning of Year	**99,291**	–
Granted	**113,880**	116,037
Exercised	**(33,093)**	–
Cancelled	**(19,950)**	(16,746)
Outstanding at End of Year	**160,128**	99,291

During the year ended December 31, 2005, the Corporation settled 33,093 PSUs for cash of $0.6 million (December 31, 2004 – nil).

c) Deferred Share Unit Plan

In October 2005, the Corporation initiated a Deferred Share Unit Plan ("DSUP"), whereby directors, officers, senior management and employees of the Corporation can elect to receive all or a portion of their annual cash compensation in the form of Deferred Stock Units ("DSU"). Under the DSUP, notional share units are issued for the elected amount which is based on the then current market price of the Corporation's common shares. Upon ceasing directorship, termination of employment or retirement, the units are settled in cash or common shares of the Corporation as determined by the Corporation. Final DSU redemption amounts are subject to change, depending on the Corporation's share price at the time of exercise. Accordingly, the Corporation revalues the DSUs on each reporting date with any changes in value recorded as an adjustment to compensation expense in the period. For the year ended December 31, 2005, $0.1 million in compensation expense relating to the DSUs was recorded (December 31, 2004 – nil) in General and Administrative Expenses and no DSUs were redeemed for cash or shares of the Corporation. The Corporation had 2,261 DSUs outstanding at December 31, 2005.

d) Stock-based Compensation

For the year ended December 31, 2005, the Corporation recognized $3.1 million (December 31, 2004 – $1.0 million) in compensation expense related to stock-based compensation issued subsequent to January 1, 2003. This is the portion of stock-based compensation that is related to 2005 services rendered and is comprised of $1.4 million ($0.7 million – 2004) in respect to the Corporation's stock option plan and $1.7 million ($0.3 million – 2004) in respect to the Corporation's Performance Share Unit Plan.

The weighted average fair value of the 443,670 options granted during 2005 was $8.22 using the Black-Scholes option pricing model. In 2004, there were 318,549 options granted at a weighted average fair value of $4.30. The following table sets out the assumptions used in applying the Black-Scholes model:

	2005	2004
Risk Free Interest Rate, Average for Year	**3.89%**	4.34%
Expected Life (in years)	**6**	6
Expected Volatility	**26 – 44%**	26 – 30%
Dividend Per Share	**–**	–

No compensation expense has been recognized for stock options granted before January 1, 2003, in accordance with note 2(i). Had compensation expense been determined based on the fair value method for awards made after December 31, 2001, but before January 1, 2003, the Corporation's net earnings attributable to common shareholders and earnings per share would have been adjusted to the pro forma amounts indicated below:

	2005	2004
Net Earnings – As Reported	**149,449**	19,452
Compensation Expense	**891**	894
Net Earnings – Pro Forma	**148,558**	18,558
Basic Earnings Per Share		
As Reported	**0.93**	0.12
Pro Forma	**0.93**	0.12
Diluted Earnings Per Share		
As Reported	**0.92**	0.12
Pro Forma	**0.91**	0.12

e) Oil Sands Project Stock Appreciation Rights Plans

During 2004, the AOSP implemented stock-based compensation plans that awarded Stock Appreciation Rights ("SARs") to certain employees. Accordingly, the Corporation as a 20 per cent owner in the AOSP, shares in the costs of these SARs. Under the first plan, SARs were granted to employees of the AOSP that entitle the holders to a cash payment once exercised, if the composite value of the weighted-average stock price of certain Joint Venture Owners' shares at the time of exercise exceeds the issue price of the SARs. The SARs vest evenly over three years and expire ten years after grant. As at December 31, 2005, a total of 85,810 SARs were outstanding in respect of this plan. During the year ended December 31, 2004 a total of 51,100 SARs were granted. During the year ended December 31, 2005 a total of 43,530 SARs were granted and 8,820 were cancelled in respect to this plan.

Under the second plan, SARs were granted to employees of the AOSP that entitle the holders to a cash payment at the end of a three-year period if the composite value of the weighted-average stock price of certain Joint Venture Owners' shares at the time of exercise exceeds the issue price of the SARs and if certain performance measures are met. As at December 31, 2005, a total of 38,950 SARs were outstanding in respect of this plan. During the year ended December 31, 2004, a total of 21,679 SARs were granted. During the year ended December 31, 2005, a total of 18,450 SARs were granted and 1,179 were cancelled in respect to this plan.

For the year ended December 31, 2005, $0.7 million in compensation expense was recorded in operating expense for these two plans (December 31, 2004 – nil). No SARs vested during the year ended December 31, 2005 with respect to either of these plans.

16. SHAREHOLDERS' RIGHTS PLAN

The Corporation has a shareholders' rights plan (the "Plan"). Under the Plan, one right will be issued with each Common Share issued. The rights remain attached to the Common Share and are not exercisable or separable unless one or more of certain specified events occur. If a person or group acting in concert acquires 20 per cent or more of the Common Shares of the Corporation, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase Common Shares of the Corporation at a 50 per cent discount from the then market price. The rights are not triggered by a "Permitted Bid", as defined in the Plan.

17. EMPLOYEE FUTURE BENEFITS

The Corporation has a defined contribution pension plan for its direct employees and as a result of the 20 per cent ownership in the AOSP, has a defined benefit pension plan for employees of the AOSP. All of the information pertaining to the defined benefit pension plan in this note represents the Corporation's 20 per cent ownership in the AOSP. The Corporation uses its fiscal year-end as the measurement date for both of these pension plans.

a) Defined Contribution Pension Plan

For the year ended December 31, 2005, the total expense recognized for the Corporation's defined contribution pension plan was $0.3 million (December 31, 2004 – $0.3 million).

b) Defined Benefit Pension Plan

For the year ended December 31, 2005, the total expense recognized for the Corporation's 20 per cent ownership interest in the AOSP's defined benefit pension plan was $0.8 million (December 31, 2004 – $0.6 million). As at December 31, 2005, the Corporation's 20 per cent share of the funded status of the defined benefit pension plan was in a deficit position of $0.7 million (December 31, 2004 – $0.01 million funded surplus). Additional information for the Corporation's 20 per cent ownership interest in the AOSP's defined benefit pension plan is as follows:

	2005	2004
Accrued Benefit Obligation, Beginning of Year	**1,860**	1,084
Current Service Cost	**821**	638
Interest Cost	**161**	110
Actuarial Loss	**821**	96
Plan Amendments	**(115)**	–
Benefits Paid	**(70)**	(68)
Accrued Benefit Obligation, End of Year	**3,478**	1,860
Fair Value of Plan Assets, Beginning of Year	**1,866**	1,131
Employer Contributions	**810**	732
Actual Return on Plan Assets	**124**	71
Benefits Paid	**(70)**	(68)
Fair Value of Plan Assets, End of Year	**2,730**	1,866
Funded Status – Plan Surplus (Deficit)	**(747)**	6
Unamortized Past Service Costs	**(115)**	–
Unamortized Net Actuarial Loss	**1,145**	301
Unamortized Transitional Obligation	**(11)**	(12)
Accrued Benefit Asset	**272**	295
Components of Net Periodic Pension Cost		
Current Service Cost	**821**	638
Interest Cost	**161**	110
Actual Return on Plan Assets	**(124)**	(71)
Actuarial Loss on Accrued Benefit Obligation	**821**	96
Costs Arising in the Period	**1,679**	773
Differences in Costs Arising and Costs Recognized in the Period in Respect of:		
Return on Plan Assets	**(32)**	(32)
Actuarial Loss	**(812)**	(91)
Transitional Asset	**(1)**	(1)
Net Periodic Pension Cost Recognized	**834**	649

The significant actuarial assumptions used to determine the periodic expense and accrued benefit obligations are as follows:

	2005	2004
Discount Rate – Expense	**6.10%**	6.50%
Discount Rate – Year-end Disclosure	**5.10%**	6.10%
Expected Long-term Rate of Return on Plan Assets	**7.00%**	7.00%
Rate of Compensation Increase	**4.25%**	4.25%

The investment strategy for the defined benefit pension plan assets is to utilize a diversified mix of global public and private equity portfolios, together with public and private fixed income portfolios, to earn long-term investment returns that enable the plan to meet its obligations. Active management strategies are utilized within the plan in an effort to realize investment returns in excess of market indices. The weighted-average asset allocation for our defined benefit pension plan at December 31, 2005 was as follows:

	Actual	*Target*
Domestic Equities	**32%**	33%
Foreign Equities	**28%**	25%
Fixed Income Securities	**34%**	37%
Money Market	**6%**	5%
	100%	100%

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Corporation's financial instruments that are included in the Consolidated Balance Sheets are comprised of cash and cash equivalents, accounts receivable, risk management activities, accounts payable and accrued liabilities, option premium liability and long-term borrowings.

a) Commodity Price Risk

The Corporation has entered into various commodity pricing agreements designed to mitigate the exposure to the volatility of crude oil prices in US dollars, thereby providing greater certainty of future cash flow from the sale of the Corporation's synthetic crude oil products. This risk management strategy is intended to protect the Corporation's base and future capital programs and ensure the funding of debt obligations. Certain of these commodity pricing agreements are accounted for as hedges, as they qualify for hedge accounting under Accounting Guideline 13 and were designated as hedges, while other commodity pricing agreements are accounted for under fair value accounting as they did not qualify or have not been designated as hedges for accounting purposes.

(i) Hedge Accounting

For the year ended December 31, 2005, the Corporation's revenues were reduced by $110.4 million (December 31, 2004 – $131.4 million) from crude oil price hedging losses. As at December 31, 2005, there were no crude oil swap positions in place.

(ii) Fair Value Accounting

During the third quarter of 2005, the Corporation purchased put options at strike prices ranging from US$50.00 to US$55.00 per barrel, averaging US$52.42 per barrel for the three year period beginning January 1, 2007. The premiums for the purchased put options were partially offset through the sale of call options at strike prices ranging from US$90.00 to US$95.00 per barrel, averaging US$92.41 per barrel for the three-year period beginning January 1, 2007, resulting in a net premium liability. Payment of the net premium liability is deferred until the settlement of the option contracts between 2007 and 2009. As at December 31, 2005, the Corporation had the following put and call options outstanding:

	2007	*2008*	*2009*
Barrels Per Day			
Put Options Purchased	20,000	20,000	20,000
Call Options Sold	10,000	15,000	15,000
US$ Per Barrel			
Average Put Strike Price	US$52.50	US$54.25	US$50.50
Average Call Strike Price	US$92.50	US$94.25	US$90.50

The fair value of the option contracts was recognized on the Consolidated Balance Sheet on the dates they were entered into. During the year ended December 31, 2005, the Corporation recognized an unrealized gain of $13.8 million on the Risk Management Asset, marking it to the fair value at the end of the period (December 31, 2004 – nil). The following table reconciles the movement in the fair value of these option contracts that have not been designated as hedges:

	2005	2004
Risk Management Asset at Beginning of Year	–	–
Net Premium	**84,976**	–
Increase in Fair Value	**13,450**	–
Risk Management Asset at End of Year	**98,426**	–

b) Credit Risk

A significant portion of the Corporation's accounts receivable is with customers in the oil and gas industry, and is subject to normal industry credit risks. The Corporation minimizes this risk by entering into sales contracts with highly rated counterparties. Risk is also minimized through regular management review of credit ratings and potential exposure to such counterparties.

The counterparties of all of the Corporation's put and call options are major financial institutions in Canada and the United States, all with investment grade credit ratings, thereby partially mitigating the credit risk associated with these financial instruments.

c) Interest Rate Risk

At December 31, 2005, the increase or decrease in net earnings for each one per cent change in the interest rates on floating debt amounts to $0.4 million (2004 – $2.2 million).

d) Foreign Currency Risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the Corporation's operating and financial results. The Corporation has revenue and expenses transacted in US dollars, and has US dollar denominated Risk Management Assets, Senior Secured Notes and Option Premium Liabilities, as described in note 18(a), note 7(a) and note 9, respectively.

e) Fair Values of Financial Assets and Liabilities

The fair values of financial instruments that are included in the Consolidated Balance Sheets, other than long-term borrowings, approximate their carrying amount due to the relatively short period to maturity of these instruments or have interest rates that approximate their fair value.

The estimated fair values of long-term borrowings have been determined based upon market prices at December 31 for other similar liabilities with similar terms and conditions, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Corporation at year-end.

	2005		2004	
	Balance Sheet Amount	Fair Value	Balance Sheet Amount	Fair Value
Floating Rate Debt				
Revolving Credit and Term Loan Borrowings	**41,000**	**41,000**	216,000	216,000
Lease Obligation	**59,205**	**59,205**	58,704	58,704
Fixed Rate Debt				
US Senior Secured Notes	**524,655**	**591,549**	541,620	628,979
Long-term Borrowings	**624,860**	**691,754**	816,324	903,683

19. COMMITMENTS AND CONTINGENCIES

a) Commitments

The Corporation and the other owners of the oil sands Joint Venture have entered into long-term third party agreements to purchase certain feedstocks on a take-or-pay basis. This commitment has been measured based on December 31, 2005 market prices. The Corporation and the other owners of the oil sands Joint Venture have executed long-term third party agreements to provide for pipeline transportation of bitumen and upgraded products, electrical and thermal energy, production and supply of hydrogen and transportation of natural gas. Under the terms of certain of these agreements, the Corporation is committed to pay for these utilities and services on a long-term basis, regardless of the extent that such services and utilities are actually used. If due to project delay, suspension, shut down or other reason, the Corporation fails to meet its commitment under these agreements, the Corporation may incur substantial costs and may, in some circumstances, be obligated to purchase the facilities constructed by the third parties for a purchase price in excess of the fair market value of the facilities.

The Corporation and the other owners of the oil sands Joint Venture have entered into long-term operating lease obligations for certain equipment related to the AOSP. The term of the lease obligations is between three and seven years. A guarantee has been provided to the lessor in order to secure attractive leasing terms and is payable when the equipment is returned to the lessor. At December 31, 2005, the Corporation's share of the maximum payable under the guarantee was $35.7 million. However, any proceeds received from the sale of the equipment would be used to offset the payment required under the guarantee. At December 31, 2005, the Corporation's share of committed lease payments amounted to $42.3 million. The estimate of lease interest obligations, excluding any committed payments, is $1.9 million for 2006, $1.8 million for 2007, $1.8 million for 2008, $0.9 million for 2009 and $0.2 million for 2010.

The Corporation has future commitments related to its Option Premium Liability as described in note 9.

The following table summarizes the Corporation's operating commitments at December 31, 2005:

	Feedstocks	*Pipelines and Utilities*	*Mobile Equipment Lease*	*Total*
2006	106,423	39,715	3,647	149,785
2007	100,771	33,463	2,358	136,592
2008	27,987	34,874	9,583	72,444
2009	9,121	34,899	18,377	62,397
2010	9,121	34,991	8,363	52,475
Thereafter	64,138	556,036	–	620,174
Total	317,561	733,978	42,328	1,093,867

b) Contingencies

(i) Insurance Claims

The Corporation has various outstanding claims under the insurance coverage provided in our Joint Venture construction policies. These claims include a loss of profits claim stemming from the fire at the Muskeg River Mine (the "Mine") on January 6, 2003, commonly referred to as Section III; a physical property damage claim stemming from the same fire at the Mine, commonly referred to as Section I; and a cost overrun and project delay claim, commonly referred to as Section IV. During the year ended December 31, 2005, the AOSP reached a settlement in respect of the insurance coverage provided under Section III. The Corporation received $19.4 million as part of this settlement and has also finalized the terms of a contingent settlement for its remaining share of the settlement proceeds in the amount of $24.6 million from those insurance underwriters that also subscribed to the Section IV. The Corporation had previously received $16.1 million, including $6.4 million during the year ended December 31, 2004, in respect to the coverage provided under Section I. However, those insurance underwriters that were involved in the Section IV claim again withheld their portion of the Section I claim totalling $19.4 million. The remaining settlement that has not been received under

either Section I or III will await the outcome of the arbitration proceedings that are presently ongoing against these Section IV insurance underwriters. Arbitration proceedings under Section IV of the Policy have been initiated to resolve the disputes with insurers surrounding this claim for payment. Following these arbitration hearings, the Corporation would expect to receive a binding decision from the panel with respect to the claim. The Corporation, in order to preserve its rights under the Policy also filed a Statement of Claim in the Court of Queen's Bench of Alberta against the defendant insurance underwriters and the broker in an amount exceeding $200 million. Aggravated and punitive damages totalling $650 million have also been claimed against the insurers. The Statement of Claim remains in abeyance pending the conclusion of the Settlement Arbitration.

During the year ended December 31, 2005, the Corporation received $3.1 million in respect of an errors and omission insurance settlement that was negotiated by the AOSP. This errors and omission insurance policy related to initial construction and as such these proceeds have been applied against the cost of the AOSP. The related settlements of both the Section I, Section III and the errors and omission insurance policy have been credited to capital, as these claims relate to costs that were capitalized as part of the construction of the AOSP, or to costs that were capitalized in association with repairing the assets damaged by the fire or those capitalized prior to the commercial operations.

No amounts, other than those collected at December 31, 2005, have been recognized in these statements relating to insurance policies, nor will an amount be recognized until the proceeds are received.

(ii) Flow-Through Shares

In connection with the issuance of flow-through shares in 2001 and 2002, the Corporation renounced Canadian exploration expenses in the aggregate amount of $29.2 million and $19.5 million, respectively. Under the subscription agreements for such flow-through shares, the Corporation has agreed to indemnify subscribers for an amount equal to the tax payable and any associated interest by the subscribers if such renunciations are reduced under the *Income Tax Act* (Canada). Discussions between the AOSP and the Canada Revenue Agency are ongoing with respect to the proper characterizations of certain expenditures included in the Canadian exploration expenses in those years. If the Canada Revenue Agency successfully asserts a change in the characterization of these expenditures, any resulting reduction in the renunciations could impact the Corporation's obligations under the indemnity provisions in these subscription agreements.

(iii) Other

The Corporation, in association with its 20 per cent ownership of the AOSP, is a joint defendant and plaintiff in a number of legal actions that arise in the normal course of business. The Corporation believes that any liabilities that might arise pertaining to such matters would not have a material effect on its consolidated financial position.

20. NET CHANGE IN NON-CASH WORKING CAPITAL

Source/(Use)	**2005**	*2004*
Operating Activities		
Accounts Receivable	**(24,834)**	(5,184)
Inventory	**(6,897)**	(5,086)
Prepaid Expense	**(3,584)**	1,262
Accounts Payable and Accrued Liabilities	**2,826**	25,401
	(32,489)	16,393
Investing Activities		
Accounts Receivable	**–**	614
Accounts Payable and Accrued Liabilities	**10,798**	(3,671)
	10,798	(3,057)

21. UNITED STATES ACCOUNTING PRINCIPLES AND REPORTING

The Consolidated Financial Statements have been prepared in Canadian dollars in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). The application of accounting principles generally accepted in the United States ("US GAAP") would have the following effects on the Consolidated Financial Statements and Other Comprehensive Income:

Reconciliation of Net Earnings under Canadian GAAP to US GAAP

Year ended December 31	*Notes*	**2005**	*2004*
Net Earnings – Canadian GAAP		**149,449**	19,452
Impact of US GAAP			
Pre-operating Items and Borrowing Costs	iii	**23**	(71)
Gain (Loss) on Crude Oil Swaps	iv	**10,202**	(8,815)
Pre-feasibility Costs	vi	**(34,503)**	(13,546)
Deferred Income Tax	ii	**7,125**	3,195
Net Earnings – US GAAP		**132,296**	215
Net Earnings Per Share – US GAAP			
Basic		**0.83**	–
Diluted		**0.81**	–

Consolidated Statement of Other Comprehensive Income

Year ended December 31	*Notes*	**2005**	*2004*
Net Earnings – US GAAP		**132,296**	215
Change in Realized and Unrealized Losses	v	**31,756**	(14,607)
Other Comprehensive Income		**164,052**	(14,392)

Consolidated Statement of Cash Flows – US GAAP

Year ended December 31	*Notes*	**2005**	*2004*
Cash Provided By (Used In)			
Operating Activities – Canadian GAAP		**211,742**	39,437
Pre-feasibility Costs	vi	**(34,503)**	(13,546)
Operating Activities – US GAAP		**177,239**	25,891
Financing Activities – Canadian and US GAAP		**(173,832)**	3,533
Investing Activities – Canadian GAAP		**(36,035)**	(43,025)
Pre-feasibility Costs	vi	**34,503**	13,546
Investing Activities – US GAAP		**(1,532)**	(29,479)
Increase (Decrease) in Cash		**1,875**	(55)

Consolidated Balance Sheet

As at December 31		2005		2004	
	Notes	*As Reported*	*US GAAP*	*As Reported*	*US GAAP*
Assets					
Current Assets		**123,426**	**123,426**	86,236	86,236
Property, Plant and Equipment	iii, vi	**1,352,605**	**1,309,080**	1,351,745	1,342,876
Risk Management		**98,426**	**98,426**	–	–
Deferred Charges	iii	**16,063**	**15,282**	18,378	17,421
Future Income Taxes	ii	**–**	**–**	14,511	56,898
		1,590,520	**1,546,214**	1,470,870	1,503,431
Liabilities					
Current Liabilities		**104,699**	**104,699**	187,909	187,909
Financial Liabilities	iv	**–**	**–**	–	61,110
Long-term Debt		**565,655**	**565,655**	662,620	662,620
Lease Obligations		**55,809**	**55,809**	53,474	53,474
Option Premium Liability		**85,416**	**85,416**	–	–
Asset Retirement Obligations		**9,094**	**9,094**	8,191	8,191
Future Income Taxes	ii	**56,445**	**26,085**	–	–
		877,118	**846,758**	912,194	973,304
Shareholders' Equity					
Share Capital	vii	**548,747**	**568,052**	545,699	565,004
Contributed Surplus		**3,474**	**3,474**	1,245	1,245
Retained Earnings (Deficit)	iii, iv, vi, vii	**161,181**	**127,930**	11,732	(4,366)
Accumulated Other Comprehensive Income	iv	**–**	**–**	–	(31,756)
		1,590,520	**1,546,214**	1,470,870	1,503,431

i) Stock-based Compensation

The Corporation accounts for its stock-based compensation plans under CICA 3870, under which no compensation expense was recognized in the Consolidated Financial Statements for stock options granted between January 1, 2002 to December 31, 2002. If compensation expense had been recorded in accordance with Statement of Financial Accounting Standard ("SFAS") No. 123, the Corporation's net earnings (loss) and net earnings (loss) per share would approximate the following pro forma amounts:

Year ended December 31	***2005***	*2004*
Compensation Expense	**891**	894
Net Earnings (Loss)		
As Reported – US GAAP	**132,296**	215
Pro Forma	**131,405**	(679)
Basic Earnings Per Share		
As Reported – US GAAP	**0.83**	–
Pro Forma	**0.82**	–
Diluted Earnings Per Share		
As Reported – US GAAP	**0.81**	–
Pro Forma	**0.81**	–

ii) Income Taxes

Under US GAAP, the net deferred income tax liability as at December 31 consists of:

Year ended December 31	***2005***	*2004*
Future Income Tax Assets		
Net Losses Carried Forward	**4,707**	61,697
Share Issue Costs	**973**	1,355
Impairment of Long-lived Assets	**796**	796
Financial Liabilities in Excess of Tax Values	**–**	22,990
Tax Values in Excess of Book Capital Assets	**5,634**	294
Future Income Tax Liabilities		
Unrealized Foreign Exchange Gain	**(30,961)**	(28,109)
Unrealized Gain on Risk Management	**(4,374)**	
Debt Issue Costs	**(2,860)**	(2,125)
Net Future Income Tax (Liability) Asset – US GAAP	**(26,085)**	56,898

The following table reconciles income taxes calculated at the Canadian statutory rate of 37.62 per cent (2004 – 38.87 per cent) with actual income taxes:

Year ended December 31	***2005***	*2004*
Net Earnings Before Income Taxes – Canadian GAAP	**223,405**	14,097
US GAAP Adjustments	**(24,278)**	(22,432)
Net Earnings (Loss) Before Income Taxes – US GAAP	**199,127**	(8,335)
Expected Income Tax	**74,912**	(3,240)
Effect of Tax Rate Changes	**1,741**	699
Non-taxable Portion of Foreign Exchange Gain	**(3,530)**	(8,815)
Non-taxable Portion of Impairment of Long-lived Asset	**–**	1,044
Resource Allowance	**(10,792)**	(5,012)
Provision to Actual	**642**	5,025
Stock-based Compensation	**858**	–
Large Corporations Tax	**3,000**	1,749
Income Tax Expense (Recovery) – US GAAP	**66,831**	(8,550)

iii) Borrowing Costs and The End of Pre-Operating Period

Under Canadian GAAP, the Corporation is deemed to have ended its pre-operating period upon commencement of commercial production, which occurred on June 1, 2003. Until that time, revenues, training and start-up costs, interest and foreign exchange gains associated with the Project during the pre-operating period were deferred and capitalized as part of the Project. Under US GAAP, the Corporation is deemed to have ended its pre-operating period upon mechanical completion of the Project, which occurred on December 1, 2002, such that these pre-operating items are expensed thereafter. Under Canadian GAAP during the pre-operating period, standby fees and foreign exchange gains or losses associated with borrowing facilities can be deferred. Under US GAAP, during the pre-operating period, these costs would be expensed as incurred. Consistent with the December 1, 2002 end of the pre-operating period, depreciation, depletion and amortization of the Corporation's Property, Plant and Equipment and Deferred Charges should have also commenced.

The following table illustrates each of these differences:

Year ended December 31	***2005***	*2004*
Pre-operating Items		
Depreciation, Depletion and Amortization	**23**	(71)
Impact on Net Earnings (Loss) Before Income Tax	**23**	(71)
US GAAP Adjustments – Prior Years	**3,197**	3,268
	3,220	3,197
Adjustment to Assets		
Adjustment to Property, Plant and Equipment	**4,001**	4,154
Adjustment to Deferred Charges	**(781)**	(957)
	3,220	3,197

iv) Crude Oil Swaps

Under Canadian GAAP, the crude oil swaps qualify for hedge accounting and the payments or receipts on these contracts are recognized in earnings concurrently with the hedged transaction and changes in the fair values of the contracts are not reflected in the Consolidated Financial Statements. US GAAP requires that all derivative financial instruments be recorded on the balance sheet as either assets or liabilities at their fair values and that changes in the derivative's fair value be recorded in other comprehensive income, with any ineffective portion of the hedge recorded in earnings for the period. Under US GAAP, the derivative financial instruments described in note 18(a)(i) as hedges would be recognized as a liability. The following table illustrates each of these differences:

Year ended December 31	***2005***	*2004*
Assets		
Increase in Future Income Tax Assets and Total Assets	**–**	22,990
Liabilities		
Increase in Financial Liabilities	**–**	61,110
Shareholders' Equity		
Decrease in Opening Deficit – US GAAP	**(6,364)**	(831)
Decrease in Accumulated Other Comprehensive Income (1)	**–**	(31,756)
Net Earnings and Ending Deficit – US GAAP		
Increase (Decrease) in Revenues	**10,202**	(8,815)
(Decrease) Increase in Future Income Tax Recovery/Expense	**(3,838)**	3,282
Increase in Total Liabilities and Shareholders' Equity	**–**	22,990

(1) Net of income tax of $19.2 million for the year ended December 31, 2004.

v) Other Comprehensive Income

Comprehensive income is measured in accordance with SFAS 130 "Reporting Comprehensive Income". This Standard defines comprehensive income as all changes in equity other than those resulting from investments by owners and distributions to owners. The Corporation had other comprehensive income arising due to unrealized losses on derivative financial instruments designated as hedge transactions. At December 31, 2005, this other comprehensive income amounted to a gain net of tax of $31.8 million ($14.6 million loss net of tax – 2004).

vi) Pre-Feasibility Costs

Under Canadian GAAP, costs associated with projects that have yet to be determined to be technically feasible can be capitalized as part of Capital Assets if certain criteria are met. Under US GAAP, costs associated with projects that have not yet been determined to be technically feasible must be expensed. During 2005, the Corporation had expenditures of $34.5 million ($13.5 million – 2004) relating to projects that have not yet been determined to be technically feasible. The cumulative effect of this difference is to reduce capital assets by $48.9 million ($14.4 million – 2004), decrease net earnings by $34.5 million ($13.5 million – 2004) and reduce Retained Earnings by $14.4 million ($0.9 million – 2004).

vii) Flow-through Shares

Under Canadian GAAP, flow-through shares are recorded at their face value within share capital. When the expenditures are renounced and the tax deductions transferred to the shareholders, future income tax liabilities will increase and the share capital will be reduced. Under US GAAP, when the shares are issued the proceeds are allocated between the offering of the shares and the sale of tax benefits. The allocation is made based on the difference between the quoted price of the existing shares and the amount the investor pays for the flow-through shares (given no other differences between the securities). A liability is recognized for this difference. The liability is reversed when tax benefits are renounced and a deferred tax liability is recognized at that time. Income tax expense is the difference between the amount of the deferred tax liability and the liability recognized on issuance. At December 31, 2002, the Corporation had recognized all renouncements of the tax deductions to the investors. The effect of this difference is to increase share capital by $19.3 million and increase deferred income tax expense by $19.3 million.

22. RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

Canadian

Financial Instruments

The CICA issued Section 3855, "Financial Instruments – Recognition and Measurement", which prescribes when a financial instrument is to be recognized on the balance sheet and at what amount – sometimes using fair value, other times using cost-based measures. This Section also specifies how financial instrument gains and losses are to be presented. A financial instrument is any contract that gives rise to a financial asset of one party and a financial liability or equity instrument of another party. These may include loans and notes receivable and payable, investments in debt and equity securities and derivative contracts such as forwards, swaps and options. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as at the beginning of a fiscal year ending on or after December 31, 2004. The Corporation plans to adopt this Section on January 1, 2007. The Corporation does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard on January 1, 2007.

Hedges

The CICA issued Section 3865, "Hedges", which replaces the guidance formerly in Section 1650, "Foreign Currency Translation" and Accounting Guideline 13, "Hedging Relationships" by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Retroactive application is not permitted. Earlier adoption is permitted only as at the beginning of a fiscal year ending on or after December 31, 2004. The Corporation plans to adopt this Section on January 1, 2007. The Corporation does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard on January 1, 2007.

Comprehensive Income

The CICA issued Section 1530, "Comprehensive Income", which established new standards for reporting the display of comprehensive income. Comprehensive income is the change in equity (net assets) of an enterprise during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during the period except those resulting from investments by owners and distributions to owners. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as at the beginning of a fiscal year ending on or after December 31, 2004. The Corporation plans to adopt this Section on January 1, 2007. Financial statements for prior periods are required to be restated for certain comprehensive income items, which at this time are not applicable to the Corporation. The Corporation does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard on January 1, 2007.

Equity

The CICA issued Section 3251, "Equity", which replaces Section 3250, "Surplus". It establishes standards for the presentation of equity and changes in equity during a reporting period. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as at the beginning of a fiscal year ending on or after December 31, 2004. The Corporation plans to adopt this Section on January 1, 2007. Financial statements of prior periods are required to be restated for specific items which are not applicable to the Corporation at this time. The Corporation does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard on January 1, 2007.

Non-Monetary Transactions

The CICA issued Section 3831, "Non-Monetary Transactions", which replaces Section 3830, "Non-Monetary Transactions" and establishes standards for the measurement and disclosure of non-monetary transactions. Section 3831 prescribes that exchanges of non-monetary transactions should be measured based on the fair value of the assets exchanged, while providing an exception for non-monetary exchanges in transactions which do not result in the culmination of the earnings process. Section 3831 eliminates this exception provided in Section 3830 and replaces it with an exception for exchanges of non-monetary assets that do not have commercial substance. A transaction has commercial substance when the entity's future cash flows are expected to change significantly as a result of the transaction. This Section applies to all non-monetary transactions initiated in periods beginning on or after January 1, 2006. Earlier adoption is permitted for non-monetary transactions initiated in periods beginning on or after July 1, 2005. Retroactive application is not permitted. The Corporation does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard on January 1, 2006.

United States

Share-Based Payment

FASB issued Statement of Financial Accounting Standards No. 123(R) (SFAS 123(R)), "Share-Based Payment", a revision to SFAS 123, "Accounting for Stock-based Compensation." This standard is effective for the Corporation as of the beginning of the first interim period or annual reporting period that begins after June 15, 2005 and may be applied under the modified prospective approach or the modified retrospective approach. This standard requires the recognition of an expense for employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The compensation cost is to be recognized over the period for which an employee is required to provide the service in exchange for the award, being the requisite service period. For liability awards, entities are required to re-measure the fair value of the award at each reporting date up until the settlement date. Changes in fair value of liability awards during the requisite service period are required to be recognized as compensation cost over the vesting period. Compensation cost is not recognized for equity instruments for which employees do not render the requisite service. The Corporation currently records an expense under Canadian GAAP for all common share options issued on or after January 1, 2003, with a corresponding increase recorded as contributed surplus. The Corporation does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard on January 1, 2006.

Exchanges of Non-Monetary Assets

FASB issued SFAS 153, "Exchange of Non-Monetary Assets" as an amendment to Accounting Principles Board Opinion No. 29 ("APB 29"), "Accounting for Non-Monetary Transactions." APB 29 prescribes that exchanges of non-monetary transactions should be measured based on the fair value of the assets exchanged, while providing an exception for non-monetary exchanges of similar productive assets. SFAS 153 eliminates the exception provided in APB 29 and replaces it with a general exception for exchanges of non-monetary assets that do not have commercial substance. For purposes of this standard, a non-monetary exchange is defined as having commercial substance when the future cash flows of an entity are expected to change significantly as a result of the exchange. SFAS 153 is to be applied prospectively and is effective for all non-monetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. The Corporation does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard on January 1, 2006.

Inventory Costs

FASB issued SFAS 151, "Inventory Costs" that clarifies the accounting for abnormal amounts of idle facility expense, freight, handling costs and wasted materials (spoilage) as they relate to inventory costing. SFAS 151 requires these items to be recognized as current expenses. Additionally, the allocation of fixed production overhead to the cost of inventory should be based on normal capacity of the production facilities. SFAS 151 is to be applied prospectively and is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Corporation does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard on January 1, 2006.

Accounting Changes and Error Corrections

FASB issued SFAS 154, "Accounting Changes and Error Corrections" which replaces APB 20, "Accounting Changes" and SFAS 3, "Reporting Accounting Changes in Interim Financial Statements" and changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS 154 establishes, unless impracticable, retrospective application as the required method for reporting a change in accounting principle in the absence of explicit transition requirements specific to the newly adopted accounting principle. This statement is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The Corporation does not expect there to be any material impact on the Consolidated Financial Statements upon adoption of the standard on January 1, 2006.

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Steve D. L. Reynish
Executive Vice President and Chief Operating Officer

David A. Dyck
Senior Vice President, Finance and Chief Financial Officer

Charles W. Berard
Corporate Secretary

SENIOR MANAGEMENT

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Vice President and Managing Director, Oil & Gas

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Vice President, Corporate Planning & Human Resources

Gerry Luft
Vice President, Downstream

Ray Morley
Vice President, Business Development

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Deputy Chairman, Emerald Capital Limited
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Valiant Trust Company
Calgary, Alberta

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
Trading Symbol: WTO

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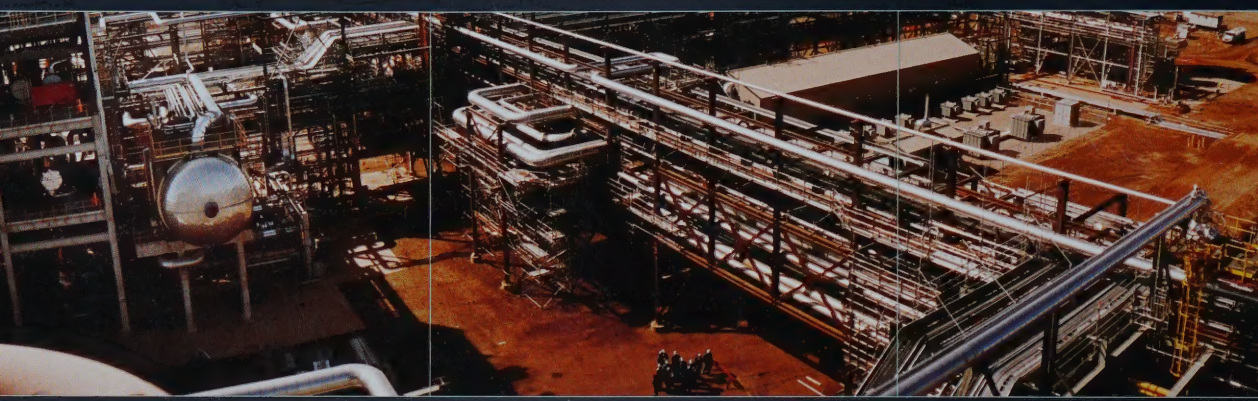

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